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CANADIAN ENERGY RESEARCH INSTITUTE

ERRATA

AN ASSESSMENT OF BENEFITS AND COSTS
OF USING METHANOL AS A MOTOR
GASOLINE EXTENDER IN
SOUTHERN ONTARIO

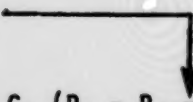
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Please make the following corrections to your copy:

Page 39:

Under No. (17)

Change from + to -


$$\text{NOC} = C_o (R_o - R_g - B_b (R_b - R_g));$$

Also change wording (see underlined section)

where: NOC = net octane credit in ¢/litre of oxygenate;
C_o = incremental octane cost in ¢/octane litre;
R_o = R + M/2 value for oxygenate;
R_g = R + M/2 value for gasoline;
B_b = butane backout/litre oxygenate; and
R_b = R + M/2 value for butane.

WORKING PAPER 85-1

**THE IMPLICATIONS OF CANADIAN
NATURAL GAS DEREGULATION**

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ROBERT T. LIDDLE**

JANUARY 1985

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PREFACE

This analysis was undertaken during an eight week period from mid-August through mid-October 1984. The purpose was to develop a qualitative examination of the implications of natural gas decontrol in Canada.

Douglas J. Haughey was the CERI Project Manager and Robert T. Liddle, President of Liddle Engineering Ltd., collaborated on a consulting basis with CERI. The analysis presented herein is based on discussions with numerous industry analysts, executives, and government policy analysts. The authors would like to thank these people and, particularly, members of the study advisory committee. Their thoughtful insights and valuable comments were extremely useful.

We would also like to acknowledge the excellent word processing by Shirley Ingstrup, Janice Morrison and Bonnie Willem, as well as the useful comments from CERI staff and others. All errors and omissions, however, remain the responsibility of the authors.

Chapter 1

EXECUTIVE SUMMARY

1.1 Background

- Consumer price resistance, interfuel competition, pipeline regulation and a supply surplus may justify a fundamental examination of natural gas regulation in Canada.
- This paper is a qualitative analysis of options for natural gas deregulation. Its objective is to stimulate discussion and comment.
- Five major points are addressed. They are: (1) existing legislation and effects, (2) decontrol options, (3) critical issues, (4) costs and benefits, and (5) an illustrative decontrol scenario.

1.2 Nature of Decontrol

- There are three commonly stated reasons to deregulate Canadian natural gas trade. They are that: (1) some consumers require cheaper gas, (2) some producers want easier access to gas markets, and (3) economic efficiency gains could occur.
- Any move to deregulation would be accomplished through three spheres of gas trade controls currently in place. They are: (1) price regulation, (2) volume controls, and (3) pipeline rate regulation.
- This paper examines a four tier spectrum of decontrol options. Tier I would be a continuation of the current regime. Tier II, similar to the export system, would have shippers (like TCPL) negotiate with distributors on behalf of producers. Tier III would allow direct contracting at negotiated prices. Tier IV, the end of the decontrol spectrum, would remove all three spheres of gas regulation.

1.3 Critical Issues

- **Resource revenue distribution** will depend in large part on the desired level of gas exploration and development. The industry will not increase exploration and development levels until new market opportunities develop. This new activity will also not occur if future market prices or fiscal policy restrict producer cash flow.
- **Security of supply** ensuring cheap gas for domestic customers may have resulted in over-protection for certain consumer classes. Customers with fuel choice alternatives may require less protection, hence freeing some surplus gas for potential export. To achieve a free market, any price flexibility must be accomplished by relaxed protection tests.

- **Industrial competitiveness** is an important issue, but it is possible that lower gas prices may simply compensate for some fundamental disadvantages faced by an energy intensive Canadian industry. It is our view that freely negotiated contractual terms are the best mechanism to set prices to industrial consumers.
- **Natural gas brokerage** would only be sanctioned in our Tiers III and IV, but discount sales may occur through non-arms-length and rebate arrangements. Allowing TCPL to aggressively compete in discount markets would hinder large scale independent brokerage activity in Tier III.
- **Contracting practices** would change radically in a direct sales environment. Purchasers (TCPL, major distributors and some brokers) would likely post block field prices for different categories of gas. More short-term contracts would evolve. TOPGAS interest cost recovery would not be affected unless the Alberta Cost of Service was dismantled. In any case, the TOPGAS agreement will not likely be modified given its size and complexity.
- **Producer equity** goals would be best achieved by allowing direct competitive access to gas markets rather than any form of proration system. Competition based on aggressive marketing, relative cost advantage and price factors is preferable to the market distortions inherent in any type of proration system. A direct contracting environment must also be present.
- **Utility regulation** will continue in any scenario short of total decontrol. Marketing and cost control incentives could emerge as well as some more flexible rate design approaches.
- **Distributor considerations** include pricing mechanisms, rate design, and implications of direct sales. In a free market it is theoretically wrong to price natural gas based on alternative fuel prices. While gas prices should be determined by the supply/demand conditions for natural gas alone, existing export restrictions may preclude this. Related to rate design, flexibility is critical and the Ontario government has promised legislation as required to allow flexibility. Finally, it is our view that direct sales are not a problem at the distributor end. The major concern relates to TCPL purchase commitments with its producers.
- **Delaying deregulation** until gas markets "are in better balance" has three drawbacks. First, it does not address current problems in gas markets. Second, it presumes that regulated gas markets will eventually come into balance. Third, it ignores measures that could provide a smooth transition to deregulation.

1.4 Benefits and Costs

- **Producers** in aggregate will experience near-term revenue reductions in any scenario where U.S market access does not increase. Certain

producers, however, will benefit at the expense of others if direct contracting proliferated. Long-term revenue potential for the industry could be more favourable if market opportunities can be exploited.

- **Consumers** could benefit from lower gas costs. Security of supply, however, will fall if prices and surplus procedures are deregulated. As mentioned above, long-term gas prices could be higher than in a regulated market. Prices would also be more volatile.
- **Transmission and distribution** pipelines could benefit from a deregulated environment that meant lower prices. Load could improve and take-or-pay recovery would be accelerated. However, cost of capital could increase if incentive rate making was adopted and risk increased. Direct contracting would also erode existing sales but we feel distribution companies would be able to renegotiate existing demand charges downward. Contract carriage would have minimal effect on revenues.
- **Exporters** would benefit from almost any deregulation scenario. Lower domestic prices would remove the floor on export prices. Relaxed protection tests would increase gas supply for export.

1.5 A Workable System

- **A Competitive Supply Program (CSP)**, illustrated in Figure 1.1 and described in Section 6.2, would allow parties to directly contract for a certain proportion (say 10-20 percent initially) of total gas supply. Producers, distributors, large consumers, or brokers could freely negotiate relatively short-term contracts within the CSP. All other gas to ex-Alberta markets would be sold at the Alberta Border Price. Governments could control the level of market deregulation by adjusting the maximum CSP volume percentage.
- **The CSP** involving a limited volume of deregulated gas could be a viable alternative to larger scale deregulation. It would provide market sensitive price formation, allow producers who so chose to sell gas into ex-Alberta discount markets, provide more export flexibility, and it would improve economic efficiency by allowing price to better reflect supply/demand conditions. Furthermore, since there is already some momentum toward less regulation, the transition to the system could be smooth.
- **Gas Producers** with flowing gas could suffer some market erosion but would be able to tender surplus gas to the CSP under existing TOPGAS terms. Local distributors could role the CSP gas into their higher cost supply, or through more flexible rate-making direct the cheaper gas to consumers needing it. TCPL could dedicate some of its contracted gas to the CSP if it chose to. Large industrial consumers could contract for discount gas through the CSP. Exporters could bid for CSP supply to move into export markets.

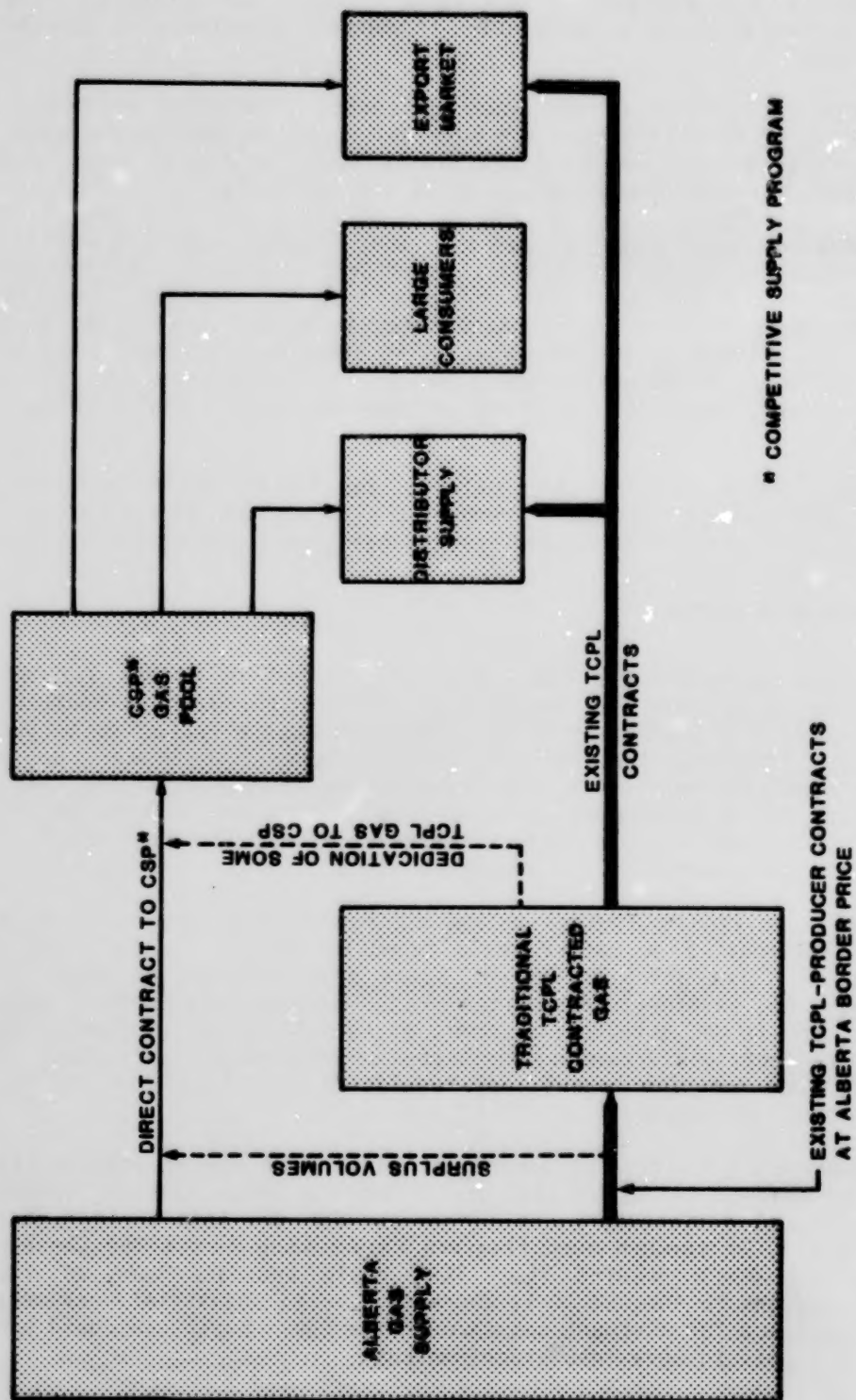


FIGURE 1.1: SCHEMATIC OF POSSIBLE COMPETITIVE SUPPLY PROGRAM

Chapter 2

INTRODUCTION

2.1 Background

The natural gas industry in Canada has reached a plateau in its long history of growth. The rapid consumption increases of the past decade have slowed due to reduced penetration of new markets and increasing efficiency of energy use. On the supply side, deliverability is at an all time high and the industry has reduced its exploration for more gas until the current surplus shows signs of evaporating.

The three cornerstones of natural gas legislation (namely price, volume, and pipeline regulation) have been firmly in place during the past decade. Now that natural gas is facing competitive pressures in all sectors, it has been argued that these regulatory cornerstones are too inflexible to respond to dynamics in domestic energy markets.

Some analysts believe that the current natural gas regulatory regime requires careful re-examination. Questions asked include:

- Are prices at their appropriate level given supply, demand and competitive pressure?
- Are the domestic volume protection tests effective, relevant and fair?
- Could changes in utility regulation better serve some of the needs of the natural gas industry and consumers?

These important questions hint at some form of decontrol of the natural gas industry in Canada. They also underline the incredible complexity of issues that must be addressed. Industry and governments are just now beginning to analyse the problems.

2.2 Objectives

This paper is designed to be a qualitative review of issues related to natural gas decontrol in Canada. Its purpose is to provide a broad framework upon which future discussions and analysis can be based. The intent is not to quantify the impacts of decontrol scenarios. These tasks could be addressed in more rigorous work later, after the important issues have been defined. Furthermore, the scope was limited to decontrol options, not any form of re-regulation or shift of regulatory emphasis.

The main objective is to provide analysis that will be a focal point for discussion of decontrol issues. This broad ranging analysis would be a "first cut" at many of the finer points involved in the decontrol debate. It is hoped the paper will stimulate discussion and comment, as well as provide direction for future study.

Due to the broad range of opinions related to the decontrol debate, many factors have been raised as issues that may, upon further scrutiny, be relatively unimportant. Because they have been vocally raised, however, they will tend to have disproportionate influence. We have attempted to address these issues as well.

2.3 Methodology and Organization

Discussions with key industry and government analysts, executives and policy makers focused on five major issues. They were:

- natural gas legislation in place and its effects;
- structure and implementation of various decontrol options;
- critical issues that must be addressed;
- the winners and losers across a spectrum of regulatory options; and
- a workable deregulation scenario for illustrative purposes.

This paper addresses these points in three major sectors. Chapter 3 examines existing natural gas legislation and a spectrum of potential decontrol options. Chapter 4 addresses the critical issues relative to decontrol. Chapter 5 outlines, for four decontrol options, the

benefits and costs to key players. Chapter 6 outlines a workable scenario and discusses prospects for future analysis.

For the purposes here, the terms deregulation and decontrol will have a synonymous meaning.

Chapter 3

THE NATURE OF DECONTROL

Natural gas decontrol has become a generic term used to describe a loosening of the regulations that control natural gas trade in Canada. This Canadian regulatory framework is composed of three major areas of government control as follows:¹

- **price** regulation of all inter-provincial and some intra-provincial gas trade;
- **volume** regulations that govern removal of gas from producing provinces as well as all exports;
- **pipeline** utility regulation that regulates cost of service and rate design.

These three spheres of gas industry regulation are more closely intertwined than some analysts may perceive. Dismantling or tinkering in one area of regulation (such as price) will have a simultaneous impact on other parts of the Canadian natural gas market controlled by one of the other spheres of regulation. It is this complexity that has made natural gas policy one of the major energy challenges in Canada and the United States.

Despite the large diversity of opinion regarding the issue, the arguments for decontrol can be distilled to three fundamental forces. They are:

- some consumers require access to **cheaper** gas supply;
- some producers want easier and more **equitable access** to natural gas markets; and
- a less regulated system could provide improved **economic efficiency**.

For consumers, the perception is that access to surplus gas supply would result in a reduction in burner-tip gas prices. For producers with shut-in supply, a decontrolled environment could provide domestic and export marketing opportunities not previously available. Finally, it has been argued that dismantling the regulatory framework

could benefit both producers and consumers by eliminating waste and rigidity in the system.

Conceptually, the arguments for decontrol are fundamentally simple. From a practical point of view, however, the implementation of any decontrol scenario is fraught with complexities that stem from years of energy regulation in Canada.

3.1 Economic Efficiency

From a national perspective, the most relevant argument for deregulation of natural gas markets is based on the concept of economic efficiency. This relates to a commodity's value to society and the resource input required to supply that product.² Although bound by some rather strict assumptions, in a perfectly competitive market there should be an optimal price/supply/demand level that maximizes economic efficiency. Any regulation or market control that impedes free market operation will result in sub-optimal allocation of resources. This results in a net cost to society. Given the highly regulated nature of Canadian natural gas market, removing regulatory encumbrances could result in a net social gain (providing no participant exercises substantial market power).

This potential social benefit resulting from a move to freer domestic and international gas markets raises a key point in the discussion of deficiencies in the existing regulatory system. Many proposals to deal with current gas market problems recommend measures that, in some cases, would result in greater regulatory burden specifically aimed at solving today's problems. This is a risky approach.

In the national context, additional regulation to repair the negative effect of past controls will only create more market aberrations in the future. There is strong evidence (such as the U.S. experience) that freer, more competitive, natural gas markets are more responsive to changing circumstances. The social benefits related to increased economic efficiency, combined with the flexibility of a freer market, tend to support the arguments for deregulation.

3.2 Energy Market Dynamics

Energy regulation has never been able to fully withstand the powerful forces that work within energy markets. For example, although

still in operation, the Natural Gas Policy Act in the United States has not been the primary influence on natural gas prices over the past 12 months. U.S. burner-tip energy markets have exerted stabilizing pressure on price and made the existing legislation nearly redundant.³ Similarly in Canada, natural gas price regulation, export controls, interfuel competition and the recession have generated a gas surplus of large proportion. Pressure exists to change the system. Meanwhile in the export market, unresponsive price regulation of the past has already yielded to powerful market forces.⁴

In domestic markets, however, the key question is whether pressures in the energy marketplace are powerful enough to force changes in the existing regulatory regime. As discussed below, the answer appears to be a qualified "yes." Strong indications are that market forces are placing irresistible pressure on some aspects of natural gas regulation in Canada. Some of these market forces are discussed below.

3.2.1 Total Energy Demand

Contrary to beliefs in the mid-1970s, energy demand has proved to be highly sensitive to the level of energy prices. Between 1973 and 1983 (a decade of significant real energy price increases), the energy intensity of Canadian economic activity (as expressed by energy consumption per unit GDP) fell by nearly 10 percent.⁵ This large response to price arose through improved (a) combustion efficiency, (b) thermal integrity, (c) energy management technology, and (d) consumer conservation psychology. Furthermore, the process will continue as old inefficient energy using equipment is retired.

Recent slow economic growth, combined with decreases in the intensity of energy use has caused net reductions in energy demand since 1979. It is our view that unless strong economic recovery occurs, downward price pressure on energy commodities will continue. Naturally, this pressure will be greatest on fuels in long supply, particularly natural gas and electricity (although cost factors may preclude significant downward movement for the latter).

3.2.2 Interfuel Competition

Given the stagnant performance of Canadian energy markets in recent years, market share growth has become an important method to

maintain or increase load. Electric utilities, burdened by a massive debt and overbuilt generating capacity, are aggressively marketing new electric heat technologies in direct competition with gas. Coal is a cost-effective competitor for boiler load. While natural gas is (on average) very competitively priced, the price and physical advantage enjoyed in certain sectors is rapidly being eroded. This interfuel competition will be the single most powerful market force facing natural gas in coming years. Competition for Canadian energy load will be fought on two fronts. They will be:

- conversion of existing oil load to natural gas, electricity, coal or a renewable energy form; and
- addition of new load as the economy expands and real energy prices moderate.

Since the potential off-oil load to compete for is fairly large, the stakes are high. Consider these figures. Roughly one-fifth (or about 650 PJ) of current oil consumption is burned in furnace and boiler applications where gas could be available.⁶ Current domestic gas load of about 1800 PJ could (adjusted for energy efficiency) ultimately increase by a factor of one-third, just from stationary off-oil conversions alone.

Related to competition for new energy load through the end of this decade, as much as 85 percent of new domestic end-use energy demand is expected to occur in the industrial sector.⁷ Given the price sensitivity of this sector, a powerful case can be made for a natural gas marketing system that is acutely sensitive to signals from the non-captive segments of the energy marketplace. Furthermore, strong penetration of industrial markets will be essential to ensure rate protection for residential customers. Therefore, the natural gas industry must be more responsive to competitive pressures in new and existing markets.

3.2.3 Transportation

The single long-haul gas transmission pipeline to central Canadian markets is operated by TransCanada Pipeline Limited (TCPL). This lack of transportation alternatives complicates any move to reduce regulation. Substantial opportunity does exist, however, to dismantle some of the rigidities in the existing system.

TCPL has stated its willingness to transport gas for other shippers, providing the gas does not back out existing TCPL sales. This view underlies the fundamentals of the current situation. Simply stated, TCPL is a transportation entity. Its other role as gas broker has proved to be a risky part of the business (witness the TOPGAS and TOPGAS II agreements). Producers have criticized the marketing efforts of TCPL and local distributors, drawing attention to problems with the utility nature of the transportation business.

Notwithstanding the TOPGAS constraints, there is a growing pressure for TCPL to carry significantly more gas to domestic customers on a contract basis. This pressure to provide transportation for others will continue only:

- if a surplus supply of natural gas exists in Alberta;
- if ex-Alberta consumers or distributors want access to cheaper gas supply through vertical integration arrangement; and
- if TCPL is unable to discount its own sales thus partially eliminating the viability of direct sales.

All of these conditions exist today, hence the increasing importance of direct sales opportunities. Some problems exist, however. First, if fragmentation of gas sales continues, a larger number of small buyers increase the risk that demand charges on some of these ad hoc sales could become unrecoverable if the buyer or seller became insolvent. Second, all small direct sales would likely require a backstop agreement with TCPL or a local distributor to reduce the buyer's risk of unanticipated volume shortfalls. Third, TCPL's TOPGAS agreement binds the pipeline to aggressive seeking of new gas markets. To protect its gas supply interests, TCPL may not voluntarily carry direct sales gas if the markets are not clearly incremental.

In the final analysis, we do not view transportation as a major impediment in any decontrol scenario where multiple gas shippers could exist. The major concern, however, is that TCPL's other role as gas buyer and seller could interfere with its function as gas transporter. This conflict will be discussed more fully later.

3.2.4 Supply Dynamics

The controversial nature of the natural gas decontrol debate has been further accentuated by diverse (and often inaccurate) views regarding the dynamics of natural gas supply. Our view of the critical factors that must be addressed relative to decontrol are discussed below.

Resource Base and Price

While the Western Sedimentary Basin has an ultimate potential of over 175 exajoules,⁸ price will determine the degree to which this resource base can be economically exploited. The key factor is that supply costs will rise over time as lower cost reserves become tougher to find. If gas prices do not keep pace with the costs to develop new reserves, supply potential will shrink. In a deregulated environment, the implication is that relatively rapid demand adjustments and relatively slow supply side adjustments could result in perpetual price volatility common to many other commodities. This will be mitigated somewhat, however, by the anticipative nature of the producing industry in responding to market opportunities.

Variable and Replacement Cost

Existing intra-Alberta discount sales have clearly demonstrated that natural gas supply can currently be contracted for prices below finding costs of the resource and certainly well below long-run replacement costs (about \$2.45 in the year 2000).⁹ A gas producer in need of cash flow might sell gas at prices marginally above his variable costs of production. The effects are two-fold. First, if heavily dependent on discount gas, a producer will be forced to secure external capital (rather than internally generated earnings) to fund further exploration or development. This is clearly an unattractive option given the current state of capital markets. Second, discount sales below replacement cost send inaccurate price signals to gas consumers. By definition, resources prices below replacement cost simply cannot endure.

Markets

The single most powerful stimulus to renewed gas exploration would be broad based natural gas market growth yielding adequate

wellhead prices. While we believe some near-term activity will occur to maintain contractual commitments, the return to aggressive gas supply development will not occur until new domestic and export markets are exploited.

* * * *

Overall, the current energy market environment seems to indicate that some adjustment to natural gas regulation is warranted. Increased need for sensitivity to burner-tip market conditions cannot easily be met with the current administered system. Furthermore, supply side pressure for broader marketing options cannot be met with the current one price, one purchaser market structure.

3.3 Market Evolution and Current Legislation

The reader is directed to Appendices A and B for a review of past and present natural gas regulation in Canada. The three spheres of regulation (price, volume, and pipeline) are very much interrelated. The Alberta Border Price has been cited as a defensive measure providing a partial counter balance to the volumetric export controls of the National Energy Board (NEB), thus shielding producers and resource owners from downward price pressure. The NEB export controls (patterned after existing Alberta gas removal controls) are linked to the availability and type of export pipeline facilities in place. Finally, the Alberta Border Price and domestic pipeline transportation costs are key components in the current domestic pricing policy and related gas marketability problems in Central Canada. None of these three spheres of regulation can be modified in isolation.

Appendix A describes the evolution of the regulatory environment in Canada. Simply stated, years of regulation, combined with changing market characteristics, have resulted in substantial volumes of shut-in gas supply, consumers resisting high prices, and pipelines with business objectives that may not match those of producers and consumers. The market has evolved to a point where some form of deregulation is a possible way to solve many of these problems.

The blanket of legislation concerning the gas industry is summarized in Appendix B. At both the Alberta and federal level legislation is in place concerning prices, cross-border volumes, and utility regulation. In Ontario, two pieces of legislation control

natural gas utilities and the granting of franchise areas. Table 3.1 summarizes the major pieces of legislation and their role in several different decontrol scenarios.

3.4 The Mechanics of Decontrol

There have been various degrees of deregulation proposed within the three major spheres of natural gas regulation (price, volume and pipeline) described previously. To adequately represent the full spectrum of options, four major "tiers" of regulation are examined in this paper. The next two sections describe these tiers and potential implementation.

3.4.1 Possible Decontrol Tiers

Table 3.2 summarizes the major features of four possible tiers of decontrol. The tiers range from continuation of the existing system to a completely unfettered free market for gas. It should be noted that these tiers are merely illustrative of the regulatory options available. Significant flexibility exists for the development of intermediate tiers or hybrid deregulation scenarios that draw on certain features of a number of tiers. This is demonstrated by a workable scenario in Chapter 6. The four regulatory tiers that this paper addresses are discussed below.

Tier I - Status Quo

In this tier, a system similar to the existing regulatory regime would remain in place. Natural gas prices would continue to be set at about 65 percent of the blended crude oil price in Toronto.¹⁰ Due to the fixed Alberta Border Price, discount sales to ex-Alberta markets would be limited to vertical integration or rebate schemes (if at all). Pipeline tariffs would continue to be regulated in the same manner and domestic protection tests would continue to restrict exports and ex-Alberta sales.

Tier II - Market Price Negotiation Only

Within the existing regulatory environment, wholesale prices could become more sensitive to market conditions by allowing TCPL and local distributors to negotiate a more competitive price. Similar to the export case, governments would approve a revised Alberta Border Price, perhaps bounded by a floor or ceiling limit. In a manner

TABLE 3.1

STATUS OF LEGISLATION UNDER DECONTROL SCENARIOS

Act or Regulation	TIER I Status Quo	TIER II Market Responsive Pricing	TIER III Market & Supply Responsive Pricing	TIER IV Free Market
A. Provincial Legislation (Alberta)				
1. Oil and Gas Conservation Act				
Act which provides the basis for the technical control of exploration and production activities related to natural gas.	- has no direct impact on pricing. - can limit production rates for conservation reasons. - basis for resolution for drainage conflicts between producers.	- Same as Tier I.	- Same as Tier I.	- Same as Tier I.
2. Gas Resources Preservation Act	- acts as a rationing mechanism dividing gas reserves between ex-Alberta consumption and Intra-Alberta consumption. - limits rate of takes on contracts by forcing an inventory requirement. - approval process of ERCB permit recommendations by Alberta government used as the pricing factor approval mechanism.	- Same as Tier I.	- would generally continue to play same role as in Tier I but perhaps relaxed somewhat. - If market responsive pricing system brought more new suppliers, existing permit holders' authorized volumes would require review. - present systems may have to be simplified for parties seeking small permits. - need for Alberta government to not use permit process as pricing approval process.	- application of Act would be suspended, or protection formula would be sufficiently relaxed to be at or below rates which would be reached commercially.

TABLE 3.1 (Continued)

Act or Regulation	TIER I Status Quo	TIER II Market Responsive Pricing	TIER III Market & Supply Responsive Pricing	TIER IV Free Market
3. <u>Natural Gas Price Agreement Act</u>	- provides authority for Alberta to enter Federal/Provincial pricing agreements, and for distribution of excess export revenues.	- would be used in same manner as Tier I except prices being approved would be those negotiated in market.	- Same as Tier II except many different prices would prevail.	- application of act suspended, or at least approval of prices would become an administrative process only.
4. <u>Natural Gas Price Administration Act</u> Provides Alberta with authority to unilaterally set prices.	- was used in 80-81 period to set prices in absences of Federal Provincial Agreement. Prices set under this Act were identical to prices set by Federal Government.	- would only be used by Alberta as "emergency" power to set prices if market responsive prices judged inadequate.	- Same as Tier II.	- Same as Tier II.
5. <u>Petroleum Marketing Act</u> This act establishes the Alberta Petroleum Marketing Commission.	- The APMC administers the ACOS (The Alberta Cost of Service) including the recovery of take or pay costs. It distributes all excess export revenues to all producers.	- Same as Tier I.	- APMC would no longer administer Alberta Border Price. Export revenues would flow directly to producers affected.	- Same as Tier III.

TABLE 3.1 (Continued)

Act or Regulation	TIER I Status Quo	TIER II Market Responsive Pricing	TIER III Market & Supply Responsive Pricing	TIER IV Free Market
6. <u>Alberta Arbitration Act</u>				
Act which defines commodity value as basis for price arbitration in Alberta gas supply contract.	- applicability of Act is overruled by Pricing Agreement Act for sales outside Alberta. - inside Alberta, commodity value prevents Alberta utilities from participating in discount market.	- Same as Tier II.	- Act would have to be suspended in applicability to allow realistic supply negotiation.	- Same as Tier III
7. <u>Alberta Gas Trunk Line Act</u>				
Established NOVA and gives NOVA right to establish own rates.	- Nova sets rates subject to appeal, APMC administers NOVA cost recovery as part of regulated field price.	- Same as Tier I.	- Same as Tier I.	- NOVA charges would be responsibility of shippers to pay. Not administered by APMC.
8. <u>Public Utilities Board Act</u>				
Controls all utilities inside Alberta	- acts as appeal board for APMC or NOVA decisions, sets rates for Alberta utilities.	- Same as Tier I.	- Same as Tier I.	- rate setting control for Alberta utilities is suspended.
9. <u>Natural Gas Price Rebates Act</u>				
Establishes mechanisms for provision of rebate to small Alberta consumers.	- effectively provides discount gas to all Alberta consumers up to 1 Bcf/Year.	- Same as Tier I.	- Same as Tier I.	- support price withdrawn.

TABLE 3.1 (Continued)

Act or Regulation	TIER I Status Quo	TIER II Market Responsive Pricing	TIER III Market & Supply Responsive Pricing	TIER IV Free Market
B. PROVINCIAL LEGISLATION (Ontario)				
<u>Ontario Energy Board Act</u>				
Established Regulatory Powers over Ontario distributors.	- approves rates of Ontario distributors.	- Same as Tier I.	- Same as Tier I.	- control over distributors costs suspended. - distributor operates as private unregulated companies.
2. <u>Municipal Franchise Act</u>				
Provides basis for awarding gas distribution franchises.	- prevents direct sales by non-franchised parties to Ontario consumers.	- Same as Tier I.	- Act amended to permit direct sales, or existing distributors ordered to act as "buy/sell" brokers for direct sales.	- limitation on franchises removed.
C. <u>FEDERAL LEGISLATION</u>				
1. <u>Energy Administration Act</u>				
a) Provides basis for Federal government to enter Federal/provincial pricing agreements.	- prices set by Federal/Provincial agreements or in absence of agreement, Federal government can set price unilaterally.	- prices negotiated in market approved under EAA.	- Possible EAP pricing guidelines.	- applicability of EAA suspended.
b) Provides basis for export adjustment fund.	- excess export revenues distributed.	- Same as Tier I	- export adjustment fund suspended, export revenues flow directly to producers supplying market.	- Same as Tier III.

TABLE 3.1 (Continued)

Act or Regulation	TIER I Status Quo	TIER II Market Responsive Pricing	TIER III Market & Supply Responsive Pricing	TIER IV Free Market
2. <u>National Energy Board Act</u>				
a) Basis for control of transmission pipelines (TCPL: West-coast).	- controls rates of TCPL, Westcoast.	- Same as Tier I.	- Same as Tier I.	- Same as Tier III.
b) Determination and allocation of exportable surplus from Canada.	- awards surplus under 25A1 test.	- Same as Tier I.	- Same as Tier I but surplus could be examined for easier export access.	- export tests application suspended.
c) Recommendation on pricing.	- recommends negotiated export prices for approval.	- Same as Tier I.	- Same as Tier I.	- free negotiation of prices.
d) Basis for forcing access of transportation services.	- approves transportation contracts for service to others in TCPL system.	- Same as Tier I.	- would force transportation service for direct market if necessary.	- would suspend power to force transportation.

NOTE: This legislation is discussed more fully in Appendix B.

TABLE 3.2
SUMMARY OF POSSIBLE TIERS OF DECONTROL

Item	TIER I Status Quo	TIER II Market Price Negotiation Only	TIER III Market & Supply Price Negotiation	TIER IV Free Market	Applicable Legislation and Authority (see legend)
A. Alberta Matters					
1. Producer Prices Ex-Alberta for Purchases by Wholesale Buyers (TCPL, Pan Alberta)	Fixed at Alberta Border by Federal/ Provincial Agreement.	No negotiation with producers directly. Negotiations held between purchasers and distributors with Alberta Border Price calculated on netback basis. Negotiated prices presented to governments for approval.	Prices negotiated by purchaser with producers and with distributor. Alberta Arbitration Act Amendment not enforced.	Prices negotiated between purchasers (TCPL) and producers and distributors. No approvals required by governments or regulator.	EA-F MGPAg-A MGPAAd-A AA-A EA-F OEB-0 MF-0
2. Direct Producer Sales to East of Alberta Markets	Sales officially at ABP. Effective discount achieved by participation or common ownership or purchaser/ producer. Alberta Removal Permit required.	Same as 1.	Sales negotiated directly at discounts. Buy/sell arrangements with Ontario distributors permitted by OEB to allow direct sales to Ontario users. Alberta permit still required.	Full negotiating freedom on price, no approvals required. No Alberta removal permit. Transportation price with TCPL, MOVA negotiated.	MGPAAd-A MGPAg-A GRP-A AA-A
3. Producer Prices Intra-Alberta	Discount prices on direct sales to Industrial users. Utility purchase prices for general market related to Alberta Border Price based on Alberta Arbitration Act.	Same as 1.	Alberta Arbitration Act not enforced for utility purchasers.	Alberta Arbitration Act gas amendments repealed. Utility general supply renegotiated with producers.	AAA-A

TABLE 3.2 (Continued)

Item	TIER I Status Quo	TIER II Market Price Negotiation Only	TIER III Market & Supply Price Negotiation	TIER IV Free Market	Applicable Legislation and Authority (see legend)
4. Alberta Cost of Service	Determined by APHC. Includes for each purchaser - NOVA costs - purchasers gas acquisition costs including T.O.P. interest	Same as I.	ACOS still in place but multi-level price structure.	Nova costs set in negotiations between purchasers and NOVA. No regulation of rates.	PN-A AGTL-A PUB-A
B. Pipeline Tariffs					
1. Ex-Alberta Tariffs on Pipeline Systems	All tariffs regulated by NEB.	Same as I.	Same as I, but contract carriage rates would be available for several classes of service.	Pipeline sets own tariffs without regulation.	NEB-F
C. Export Matters					
1. Pricing of Export Gas	Prices negotiated in export markets and resultant agreements presented for approval. Floor set by Toronto City Gate price.	Same as I.	No limitation to Toronto City Gate price. Export flowback discontinued.	Same as III.	EA-F NEB-F NGPAG-A MGPAD-A PN-A AA-A
D. Consumer Matters					
1. Pricing of Domestic Gas to Distributors by Existing Gas Wholesalers	Prices set by Federal/Provincial pricing Agreements.	Prices negotiated between gas wholesaler and distributors, then presented to governments for approval. Floor and ceiling prices may apply.	Same as II, but floor and ceiling prices could apply.	Freely negotiated.	EA-F NEB-F NGPAG-A MGPAD-A PN-A AA-A

TABLE 3.2 (Continued)

Item	TIER I Status Quo	TIER II Market Price Negotiation Only	TIER III Market & Supply Price Negotiation	TIER IV Free Market	Applicable Legislation and Authority (see legend)
2. Pricing of Domestic Gas to Distributors by Gas Brokers or Producer Direct Sales.	Vertical integration may provide effective discount.	Same as I.	Prices negotiated between gas broker and distributor. Floor or ceiling prices could apply.	Free negotiations.	
3. Pricing of Domestic Gas by Distributors to Consumer at Burner-Tip.	Prices set by distributors with rates structures approved by OEB.	Same as I.	More rate variation allowed by OEB. Regulations changed to allow direct sales.	Distributors set own rates, no approvals required.	OEB-0 MF-0
4. Price Adjustment Fund.	Surplus revenues from all exports distributed to all producers in Alberta by APWC.	Same as I.	Export revenues flow directly to producers supplying export gas.	Export revenues flow to export seller (TCPL). Sharing of revenues, matter of negotiation between producers.	EA-F PM-A
E. Permit and License Matters					
1. Export Licences from Canada.	NEB recommends export licenses from Canada to Federal Government for approval based on surplus tests, etc.	Same as I.	Same as I, but surplus criteria could be relaxed.	No export licenses required.	NEB-F

TABLE 3.2 (Continued)

Item	TIER I Status Quo	TIER II Market Price Negotiation Only	TIER III Market & Supply Price Negotiation	TIER IV Free Market	Applicable Legislation and Authority (see legend)
2. Removal Permits from Alberta	ERCB recommends removals from Alberta based on surplus test. Alberta government may hold approval relative to pricing.	Same as I, but sur- plus criteria could be relaxed.	Same as I, but surplus criteria could be re- taxed.	No Alberta removal permits required.	GRP-A

LEGEND (act - authority):

Federal

EA - Energy Administration Act
NEB - National Energy Board Act
NP - Northern Pipeline Act

Alberta

NCPag - Natural Gas Pricing Agreement Act
NGPAd - Natural Gas Pricing Administration Act
AA - Alberta Arbitration Act
AGTL - Alberta Gas Trunk Line Act
PUB - Alberta Public Utilities Board Act

Ontario

OEB - Ontario Energy Board Act
MF - Municipal Franchises Act

similar to the export system TCPL would have to demonstrate producer approval of the new price.¹¹ Limited direct sales similar to Tier I would continue, but likely at a lower volumetric level, reflecting the more competitive border price.

While a total dismantling of existing surplus tests is not envisioned in this tier, pressure currently exists to review protection rules for effectiveness and fairness. This is discussed further in Section 4.2.

Tier III - Market and Supply Price Negotiation

Direct contracting of gas supply would become possible as ex-Alberta gas movement would be priced on a contract-specific basis. Transportation would be negotiated with TCPL and local distributors directly. The freer contracting environment would require more removal permit flexibility. Existing TOPGAS producers would have the option to participate in TCPL discount marketing programs or move surplus quantities to other purchasers.

Similar to Tier II, a total dismantling of existing surplus tests is not envisioned in this tier. A review of current tests could occur to relieve downward pressure on price. This is discussed further in Section 4.2.

The Alberta Border Price will no longer exist but instead would be replaced by various negotiated prices at the field gate. In theory, there could be as many prices at the Alberta Border as there are contracts (+650 in TCPL's case). In practice, however there will be a manageable number of price groups, perhaps based on the purchase activities of end-use distributors and a small number of brokers. At the distributors' end, the new suppliers would either have to arrange for a sale/repurchase arrangement through existing Ontario distributors, or seek their own separate status as a "distributor" to meet the requirements of the OEB Act and the Municipal Franchises Act in Ontario. Normal T-service rates on TCPL could apply.

Tier IV - Free Market

This end of the decontrol spectrum may never be workable. All three major spheres of regulation (price, pipeline and volume) would be dismantled. The resulting environment would mean absolutely free

movement of gas to export markets with pipelines extracting whatever economic rent possible between the field gate and the burner-tip. Clearly, this tier would not occur while natural gas is still viewed as a scarce and strategically vital resource or while transporters and distributors are in a position to exercise monopoly power.

3.4.2 Potential Implementation

Figure 3.1 illustrates an implementation time-line (for discussion purposes only) of the four decontrol tiers discussed above. The time-line utilizes a "cascading" approach where the industry could move sequentially from tier to tier, or stop anywhere along the process. Table 3.2 summarizes the role of major legislation under each tier of decontrol. Details of implementation are discussed below.

Tier II - Market Price Negotiation Only

At this level of decontrol, the assumption is that governments would not change or repeal any of their legislation, but would simply utilize available discretionary powers within their respective Acts. Similarly it is assumed that no government of a consuming province would enact any legislation to try to recontrol pricing at the consuming point. It may well be that some technical amendments to regulations are required, and it is assumed these will be done as necessary.

Given that adjustments to the Alberta Border Price need not coincide with the contract year, it is possible to implement market price adjustment as soon as they are negotiated between TCPL and distributor and examined by producers.

Tier III - Market and Supply Price Negotiation

It is assumed that to reach this tier of decontrol, some further transition period will be required beyond that necessary to reach Tier II. This would give domestic gas purchasers (principally TCPL and Pan Alberta) time to re-establish negotiated buying and selling prices with their producers and consumers. It would also enable direct marketing and contracting relationships to be established and allow for required changes in gas supply arrangement with local distributors.

Tier IV - Free Market

Transition to a free market could require five years or more to implement. This implementation would require political and market circumstances that are not likely to exist in the next few years. It would require a clear perception that domestic gas markets would not be in jeopardy and that pipelines would not exploit their monopoly position in the marketplace. These factors will be addressed more fully later.

Footnotes

¹This does not include fiscal arrangements such as royalties, Petroleum Gas and Revenue Tax, Petroleum Incentive Payments, etc. In a broad sense these could be classified under the "price" sphere of regulation.

²Richard H. Leftwich, The Price System and Resource Allocation, 1976, p. 20.

³New gas is being contracted at prices less than the NGPA maximums, clearly a sign that market forces are exerting a downward influence.

⁴In July 1984 the Federal Government announced a move to market oriented pricing in export markets. This was in response to depressed U.S. demand for Canadian gas.

⁵National Energy Board, Canadian Energy Supply and Demand 1983-2005, September 1984, p. 14.

⁶Statistics Canada, Quarterly Report on Energy Supply and Demand in Canada, Catalogue 57-003.

⁷Estimates from CERI's energy demand modeling system.

⁸National Energy Board, Reasons for Decision: Gas Export Omnibus Hearing, 1982, January 1983.

⁹National Energy Board, Canadian Energy Supply and Demand 1983-2005, September 1984, p. 57.

¹⁰Due to increases in TCPL tolls and the fixed nature of the Alberta Border Price, it is assumed that the 65 percent ratio will rise slightly over time.

¹¹Producer consensus will be impossible to achieve. Just as in the export case, however, the bulk of supply is controlled by a relatively small number of producers. Favourable reaction from these producers will carry significant weight.

Chapter 4

THE CRITICAL ISSUES

A number of major issues are relevant to the question of domestic natural gas decontrol. These include:

- resource revenue distribution;
- security of supply;
- industrial competitiveness;
- natural gas brokerage;
- contracting practice;
- producer equity;
- utility regulation;
- distributor considerations.

These issues will ultimately dictate the direction of future gas policy. They are discussed below.

4.1 Resources Revenue Distribution

Because near-term natural gas revenues could fall under any type of decontrol scenario, short of complete market access for producers, the question of resource distribution becomes critically important. Inevitably, the issue will boil down to a risk and revenue trade-off between government and the producing industry, although government tax share will tend to decline as energy prices fall.

As summarized in Table 4.1, the distribution of natural gas revenues falls into five major categories as follows (incentives and subsidies excluded):¹

- pipeline operating costs and return on capital;
- federal resource charges including Natural Gas and Gas Liquids Tax (NGGLT), Canadian Ownership Special Charge (COSC), and Petroleum and Gas Revenue Tax (PGRT);
- provincial royalties;
- producer operating costs, return on capital, and retained earnings requirements; and

TABLE 4.1
DISTRIBUTION OF NATURAL GAS REVENUE

Revenue-Sharing Cost Component	Cash Flow		Taxes and Charges			Incentives (Positive)	
	Operating Expenses	Return on Capital	Income and Municipal Taxes	Provincial Resource Charges	Federal Resource Charges	Provincial	Federal
Distribution Tariff	provincial rate regulation	provincial rate regulation	provincial rate regulation	-	-	-	DSEP
City Gate Taxes	-	-	-	-	NGGLT, COSC	-	-
TCPL Tariff	NEB rate regulation	NEB rate regulation	NEB rate regulation	-	-	-	tariff increase cushion (COSC funded)
NOVA Tariff	PUB rate regulation on appeal	PUB rate regulation on appeal	PUB rate regulation on appeal	-	-	-	-
Wellhead Price	operating costs and retained earning requirements	as business conditions permit	as per tax systems	Royalties	PGR	PIP, other incentives	PIP, other incentives

LEGEND:

- COSC - Canadian Ownership Special Charge
- DSEP - Distribution System Expansion Program
- NEB - National Energy Board
- NGGLT - Natural Gas and Gas Liquids Tax
- PIP - Petroleum Incentive Payments
- PGR - Petroleum and Gas Revenue Tax
- PUB - Public Utility Board

- income and municipal taxes.

Given that the vast majority of pipeline transportation costs relate to capital expenditures already incurred, there is very limited flexibility for downward adjustments in current transportation costs. Similarly, while the income and municipal tax systems could be adjusted, they have not often been noted as vehicles to bear the brunt of natural gas revenue reductions. This leaves three targets for absorbing gas revenue decreases. They are (1) federal resource charges, (2) provincial royalties, and (3) producer cash flow.

4.1.1 Federal Resource Charges

Federal resource charges such as COSC and PGRT are all potential targets for reduction if natural gas revenue fell. Practically speaking, however, flexibility is not all that great. The NGGLT is already zero. The COSC, while outliving its stated purpose, represents only about 3 percent of burner-tip industrial gas prices in Ontario.² In addition, part of the \$0.14 per gigajoule levy is already subsidizing TCPL rate increases down to the general inflation level. The PGRT could be modified, but given federal government revenue requirements it may continue to hurt the bottom line for gas producers, even though government expenditure cuts are possible.

4.1.2 Provincial Royalties

For aggressive inter-provincial buyers or sellers of natural gas, the Alberta Border Price may not be much more than a deemed price for royalty purposes. Through vertical integration of producing and consuming entities, natural gas could cross the Alberta border at the regulated price, but sharing in producer's revenue would substantially reduce the effective price paid. For willing sellers, there is nothing fundamentally wrong with this approach. With less price regulation, however, the Alberta government could move to protect royalty revenue by creating a formal deemed price for royalty purposes (say, the current level of the Alberta Border Price). If average gas prices declined, effective provincial royalty rates would rise, impinging on producer cash flow and perhaps stifling industry activity. A higher effective royalty rate would raise the minimum price producers would accept for gas.

4.1.3 Producer Cash Flow

The final target to absorb revenue reductions is the producing industry itself. Clearly, any reduction in natural gas revenue may be borne in large part by the producing industry. In fact, if federal and provincial governments move to protect their absolute share of gas revenue, the impact on the producing industry could be serious. Short-term gas supply will not be substantially affected by cash flow reductions because large reserves and deliverability are in place. In the longer term, however, producer cash flow must be adequate to fund new exploration and development. The supply cost of new reserves is expected to rise over 50 percent in real terms over the next 20 years.³ The implication is that similar real increases in producer cash flow will be required to maintain the pace of reserve additions that many gas supply forecasts are based on.

4.1.4 Striking a Balance

In any scenario where protection tests remained unchanged, the one near certainty is that average gas prices would fall if deregulated today (although delayed deregulation could mitigate this downside pressure). It is our view that both levels of government will be forced to balance their revenue objectives with the desirability of keeping the producing industry operating at high levels.

There is an argument that in today's gas market environment (surplus supply and limited domestic demand) the producing industry should not be aggressively developing new gas supply in any event. Therefore, governments should be maximizing their revenue, limiting producer cash flow, and letting the surplus work itself down.

We do not agree with this view for three reasons. First, long-run forecasts of Canadian gas supply (upon which protection tests are based) assumed that industry cash flow would continue at reasonably healthy levels. Therefore, reduced reserves additions resulting from reduced cash flow could result in less domestic supply security than first thought. Second, the medium- and long-term outlook for the U.S. market is excellent. Therefore, strong industry cash flow could help develop supply to exploit more of this market. Third, petroleum industry capital investment activity is thought to have a greater economic impact than many other types of spending. Therefore, given the over-capacity in the Canadian economy, strong petroleum industry activity will be beneficial in terms of investment and employment.

As a final comment, if prices would fall more than volumes would rise in a near-term deregulated environment, there is no strong motivation for producers to embrace any type of decontrol option that did not provide additional gas market opportunities. However, selective discounts to specific industries (such as petrochemicals) may result in net revenue gains. It is not clear whether this type of price discrimination is equitable or workable in the overall system.

4.2 Security of Supply

"A consumer's security of supply is often a producer's insecurity of demand."⁴ This statement has proved very true for the Canadian natural gas industry. The "special" status of natural gas has spawned rather elaborate protection procedures that have helped create (together with price regulation, slow growth and exploration incentives) a gas surplus of apparently long-term nature. There are four important issues:

- How effective and necessary are current protective procedures?
- What effect do they have on the existing surplus and who should pay for the costs of proving up reserves well in advance of the need for them?
- Do they artificially restrict gas market access of some producers?
- What would be the effect of free movement of gas?

These issues are addressed below.

4.2.1 Effectiveness of Protection

The major problem with any particular test relates to its operational effectiveness. For example, even though sophisticated reserves and deliverability tests are in place, some analysts fear a peak day deliverability shortfall may soon develop in Alberta. This modest shortfall would be due to sharply curtailed producer investments in maintaining peak field deliverability. The deliverability tests would not reflect this problem due to the seasonal nature of demand.

Clearly, market forces can be more powerful than many believe. In the Alberta case, surplus gas and limited market prospects have seriously dampened drilling activity. While we expect gas drilling to rebound, market forces will continue to have a depressing effect on

activity. Therefore, one must expect that the true effectiveness of the protection tests may be always subject to question.

On the demand side, the protection tests may provide unnecessary long-term supply security for certain customer classes. Dual-fired industrial customers, for example, are not dependent on gas. Therefore, the protected volumes based on this load class may be more effectively utilized elsewhere. If the downward supply response to the protection tests is significant, providing unnecessary reserve protection for dual-fired customers may provide zero benefit on the demand side and substantial cost (in terms of inventory) on the supply side.

4.2.2 Artificial Surplus

There is no question that the protection tests hold more gas for domestic consumers than is currently needed. It is also true that the large surplus of natural gas in Canada would push near-term prices down in a decontrolled marketing environment. The current Alberta Border Price has been defended on this basis. It is not clear, however, that the short-term situation would be substantially different if the protection tests were relaxed or removed (except in cases where price flexibility could exploit spot sales opportunities).

Natural gas exports to the United States are still well below licensed maximums. Therefore, unless more price flexibility also existed, more gas available to the export market would not significantly affect domestic markets in the short term. The existing Alberta surplus would still be present and the U.S. market would not be an immediate outlet.

The real effect would come in the medium and long term. In an unchanged domestic environment over the long term, the mandated surplus would keep prices at levels lower than those in the U.S. If the protection formulae were relaxed, however, domestic prices would tend to rise to U.S. levels.

4.2.3 Ease of Access

Under the current conditions with fixed prices in the domestic marketplace and with ample authorized supply available to the major domestic suppliers, there are no restrictions being caused by Alberta removal permit availability in a total sense. However, major purchasers cannot compete with the "vertical integration" deals such as Soquip and Simplot, therefore there is pressure on the consuming side

to allow direct market access. For these direct sales, however, obtaining an Alberta removal permit is potentially restrictive and time consuming. They may be forced to "rent" a permit from an existing permit holder.

If these conditions continue to persist for a period of time, then there will be pressure on the ERCB to expedite the Alberta removal process for small volume applications by eliminating the hearing process, etc. Since there is already resistance from existing domestic market suppliers (TCPL and Pan Alberta) and some producers, awarding removal permits to the "vertical integrators" would be vigorously resisted.

Another possibility would be to force review of permit volumes by existing permit holders if it can be shown that the markets they are serving do not require the permit volume they hold. Again, the existing permit holders would resist such moves.

4.2.4 Free Movement of Gas

Our Tier IV examines the situation where the Alberta removal permit and NEB export license procedures are suspended. While this step would bring about major changes in the natural gas industry, it may not be the drastic move originally thought. There are two reasons.

First, in an unrestricted contracting environment, a commercially practical reserves/production ratio of 12 or 15:1 would likely evolve. This is substantially less than the current 25:1 protection requirement, but is within the possible range of reduced protection test based on more realistic protection requirements for specific customer classes. Therefore, in terms of total inventory, adjusted domestic requirements (by customer class) may be roughly met in a free contracting environment.

Second, if licensing procedures were dropped, contractual arrangements could be used to guarantee domestic supply. Exporters could be required to direct export volumes to Canadian markets if domestic shortfalls developed. Furthermore, domestic utilities and large consumers could contract long-term gas deliverability to achieve security of supply. In this situation, export contract durations would shorten to reflect the interruptibility of Canadian supply. Domestic contracts would lengthen to reflect guarantees of long-term reserves

and deliverability. Prices may rise to reflect the cost of long-term supply security.

4.3 Industrial Competitiveness

Energy intensive Canadian industries compete in North American and world markets with producers who may have access to cheaper energy. Given the energy intensity of these industries (for example pulp and paper, iron and steel, and chemicals), cheaper natural gas supply could be of critical importance in highly competitive markets. However, some important questions are raised.

First, are competitive problems faced by Canadian industry a function of factors other than energy costs? These factors could include:

- process inefficiency;
- distance from markets;
- trade barriers;
- financial circumstances;
- labour costs; and
- climate.

The use of reduced natural gas prices to balance competitive disadvantages is often criticized as a stop gap solution to a more fundamental problem. While this may be true in theory, we take a more practical view. If an industrial gas user is truly in dire competitive straits, he must have the ability to seek lower energy costs. Producers, however, must also have the right to refuse to sell gas at the price he requires. In such a case, the plant will close. The fundamental point is that both parties are free to negotiate contractual terms. This is the nature of a market sensitive pricing system.

Second, is it incumbent upon gas producers to absorb gas transportation cost differentials that exist due to the location of Canadian industrial enterprises? Gas users in the U.S. Gulf Coast region have had access to cheap local supply and lower cost access to markets. For the Gulf Coast petrochemical industry, this has provided a strong price advantage. Given the long-haul nature of Canadian gas transportation, similar price breaks could yield wellhead prices approaching replacement cost of the gas.

Third, in the broader context, is parity of gas costs between Canadian and U.S. industry a logical goal? Creating any sort of direct link between U.S. industrial gas prices and those in Canada could create a unique situation. For example, it would be similar to instructing a Canadian bank to provide long-term debt at 6 percent to a Canadian manufacturer just because the manufacturer competes with a 20-year old U.S. firm that acquired that same type of financing in the 1960s.

Fourth, a gas pricing policy driven totally by market needs ignores the fundamental importance of supply dynamics. Just as the a supply-side cost focus is slow to respond to market signals, a focus targeted only on competitive needs of consumers could ignore important signals on the supply side. For example, in a decontrolled environment such as our Tier III, Ontario petrochemical producers could negotiate their best deal possible. Canada's long-term resource base and supply costs are much more favourable than in the U.S. One would expect gas cost disadvantages to be reversed over time.

4.4 Natural Gas Brokerage

The current regulatory system does not explicitly provide for ex-Alberta brokerage of discount natural gas. In practical terms, however, there are two ways such a deal could be structured:

- vertical integration of buyer and seller; or
- rebate to seller a portion of Alberta Border Price.

For both schemes the Alberta Border Price is the official selling price. The price discount arises from shared production profits or some form of direct payment. Alberta royalty revenue is not affected.

It is our view that a move to our Tier II negotiation of market prices would reduce the role of brokers in the marketplace relative to today. The reason is that while institutional regulations would not change, gas prices would become more competitive. Therefore, the same impediments to brokerage would exist but pressure for reduced prices would be much less.

In a Tier III environment where direct buyer/seller negotiation is possible, the outlook for gas brokerage would depend entirely on how aggressive the major marketers become. If TCPL moved abruptly to offer competitive gas to every customer possible, no small broker could

compete. Practically speaking, however, brokerage opportunities would likely increase as market niches developed.

As a rule of thumb, the amount of brokerage activity in the future will be a good barometer of traditional marketers' effectiveness. The pressure today to allow brokerage of direct sales gas is merely a symptom of marketing problems stemming from pricing and market access inflexibility.

4.5 Producer Contracting Practice

Since the advent of government controlled pricing, all ex-Alberta contracts have had their pricing provisions overruled by the combined federal and provincial legislation. Even those contracts not affected by the legislation (primarily intra-Alberta sales) have nevertheless used the Alberta Border Price as a reference. Similarly, the existence of the export flowback through the Price Adjustment Fund has influenced the setting of contract prices. The intra-Alberta producer implicitly takes into account his estimate of the price adjustment when negotiating his "free market" prices.

Another key feature in contracting practice during price controls has been the contract take or pay modifications entered into by virtually all purchasers of price controlled gas. These modifications have been in the form of reductions of contractual obligation to take gas, modification of the terms and conditions of advances, interest charge recovery, and repayments of take or pay funds provided by gas purchasers.

Volume controls as represented by the permit and licensing procedure of the ERCB and NEB continue to have a significant impact as well. In addition to the built-in surplus, the fact that gas removal must be government permitted limits the number of marketers moving gas out of Alberta. Furthermore, the practice of franchising distributors limits the number of participants in the gas business.

4.5.1 Effect of Decontrol on Contracting

In a Tier II scenario where the principal contractual negotiation would occur between TCPL and the Ontario and Quebec distributors,

the negotiated prices reached by TCPL and the distributors would still be submitted for approval by the two government levels.

The key practical matter in the contractual negotiations would be the satisfaction of the producing provinces and producers' concerns that TCPL would adequately represent their interests. Given the sophisticated analytical capability and market awareness of today's producers and governments, TCPL would have a difficult task presenting any deal that was less than fair. Nevertheless, TCPL's monopsony position would, combined with the pipeline's clear incentive to lower gas prices, maintain perpetual downward pressure on the market negotiated price structure.

In a Tier III scenario where it is assumed that price negotiation would proceed with both the marketplace and the producers, the ability for direct sales would substantially reduce monopsonistic tendencies. In legal terms, the prices in producer contracts would revert to those that would have been in place prior to the government price controls of 1975. However, these prices would be recognized as unrealistically low in terms of current market conditions. Purchasers would likely post a single field price adjusted for location and contract terms.

With direct contracting and free price negotiation, one could expect to see considerably more activity by large industrial consumers to contract directly with producers willing to sell gas at lower prices. However, to achieve these direct sale links the participating producers and buyers would still have to obtain an ERCB gas removal permit, transportation agreements with TCPL and distribution utilities, and approvals as franchised distributors in Ontario (unless some buy-sell agreement were reached). The need for other non-price approvals could still inhibit direct sales. Specifically, the ERCB must find a provincial surplus before awarding a permit. If a direct sales purchaser could not obtain his permit, it is not likely that existing purchasers would be willing to share their permits without significant compensation.

The deregulated contracting mode would allow existing large purchasers, particularly TCPL, to enter the discount market fully. Given the surplus supply presently available to TCPL, it should be possible for TCPL to meet and beat any price competition. In a contracting sense there would be little incentive for a consumer to

contract directly with a producer unless there were some additional advantages such as a non-arm's length relationship.

4.5.2 TOPGAS Costs

In a free gas market, the Alberta Cost of Service could be eliminated. In this situation, TCPL becomes liable for the TOPGAS interest cost and would no doubt seek to have these costs recovered as part of their NEB regulated rates. For the TOPGAS consortium, the recovery of TOPGAS principal and interest would continue unaffected by the nature of TCPL's cost recovery or the selling price of gas. The TOPGAS agreements call for the return each year of specific sums of money, not volumes of gas. However, increasing volumes of gas sold by TCPL do cause the schedule of TOPGAS loan repayments to accelerate.

Some gas producers feel they were forced into the TOPGAS agreements and are unduly burdened with a disproportionate level of TOPGAS costs. Therefore, to relieve these inequities any modification to the natural gas regulatory system would require a re-examination of both TOPGAS agreements. It is our view that such a substantial revision of TOPGAS contractual terms is unlikely due to the size and complexity of the deal. Furthermore, since the agreements are structured to be independent of gas market changes, there seems to be no technical TOPGAS impediments to a decontrol scenario where TOPGAS gas sales remain flat or rise.

The exception is a case where gas sales under the TOPGAS agreements decline. Given the annual 2 percent per month for 5 months repayment schedule, reduced gas sales and unchanged TOPGAS repayments could cause cash flow problems for some producers. Unfortunately, these producers could also be the ones unable or unwilling to pull out of the TOPGAS agreements by repaying the TOPGAS principal. In any case, APMC rulings may preclude this possibility. Even if these individual producer cash flow problems became so severe that some TOPGAS repayment was threatened, two factors tend to reinforce the belief that TOPGAS lenders would be reluctant to restructure the deal. First, if there were more than one producer signitor to the original contract, other producers may be liable for his share of take-or-pay repayment. Second, TCPL is liable to TOPGAS for up to \$400 million in bad debts resulting from producer defaults.

The TOPGAS consortium would be at only limited risk from non-recovery of TOPGAS prepayments. Therefore, even though direct

sales erosion of TCPL markets would cause real hardship for producers with no alternatives to TOPGAS, it is difficult to envision a scenario where TOPGAS would be substantially modified (unless there was unilateral government action).

4.5.3 Individual Producer Impacts

The disappearance of a single regulated price would probably not mean that prices would be negotiated contract by contract. In practice, price blocks would emerge that reflected price premiums/discounts for matters such as contract flexibility. In a totally decontrolled environment, the actual costs of take-or-pay interest on individual contracts would become identified and payable (recoverable) on a contract by contract basis.

4.6 Producer Equity

The proportion of a producer's gas supply that is under contract varies widely within Alberta. The spectrum is broad, ranging from producers with no flowing gas to producers with TCPL "area contracts" under which substantial volumes of new gas had been connected, even in times of surplus supply.

Producers with a large proportion of flowing gas tend to be some of the more established players in industry. As such, their advantageous position with established gas purchasers has evolved over many years, but they still have surplus gas to sell. Because they were first to bring their gas to market (incurring all associated risks and costs), they expect first access to new markets.

Producers with a lesser proportion of flowing gas are often more recent entrants in the business. These producers believe existing producers and purchasers have no special right to new markets and advocate easier access for unaffiliated producers.

Our view is that a fundamental difference exists between "equal" and "equitable" gas market access when examining contracted vs. uncontracted producers. Equal market access (like a gas proration system based on proportionate deliverability or reserves) merely shares production on a proportionate basis. This is not necessarily fair, nor does it reduce gas market regulation. Therefore, the concept of "equal" treatment is unacceptable in the deregulation context.

In our view, an equitable (or fair) system is preferable and must reflect the competitive strengths and weaknesses of individual producers. Perhaps small aggressive producers (through direct sales) should be allowed to compete in the traditional markets of more established companies. Similarly, established producers should be able to exploit their low cost supply position to aggressively compete in all markets.

The implication is that gas markets could move toward deregulation with "equitable" market access as a fundamental principal. Both contracted and uncontracted producers would benefit in the long run. Conversely, the concept of "equal" access is a step to more regulation, compounding existing aberrations in gas markets. We therefore reject it as a viable mechanism in the context of deregulation.

4.7 Utility Regulation

Current natural gas utility regulation in Canada has been criticized for its tendency to encourage inefficient business practices. It has been argued that complete reimbursement of operating costs and a regulated return on invested capital have caused utilities to:

- propose facility expansions that may not be economic;
- overbuild facilities relative to acceptable engineering standards;
- neglect their role as the marketing agent for gas producers (including rate-making practices); and
- incur operating costs that do not reflect efficient business practice.

While current utility regulation certainly encourages such pipeline tendencies, the solution is probably not a total abandonment of the existing system (except perhaps in Tier IV).

The utility incentive measures often discussed likely represent a move to greater (rather than less) regulatory scrutiny. While some effective measures such as marketing incentives, cost control incentives, and load forecast accountability could help correct problems with current utility regulation, the costs of regulation increase.

A workable incentive system could benefit all aspects of the gas industry and allow utilities to earn a rate of return exceeding that possible in the current environment. A more efficient gas marketing system should evolve.

One method of potentially reducing the rigor of the current system may be to regulate transmission companies and distributors on an "appeal" basis similar to the NOVA model. The utility would submit its cost of service and tolls for approval. Intervenors could appeal certain parts of the application, thus ensuring that they still have a strong voice. Presumably, in an effort to avoid costly and time-consuming hearings, utilities may be more reasonable in their rate requests. Clearly, however, the appeal process could degenerate to full scale hearings if intervenors disagreed with most aspects of the utility's application.

4.8 Distributor Considerations

4.8.1 Commodity Value vs. Competitive Pricing

In the absence of competitive market conditions, a commodity value approach to gas pricing has been used in the past. With the Arbitration Amendment Act (1973),⁵ the burner-tip commodity value of natural gas has come to mean the weighted average of efficiency adjusted alternative fuel prices in a certain sector or market area.⁶

In a free market, basing natural gas prices on alternative fuel prices is theoretically wrong. If a competitive gas market exists, prices should be based on the supply and demand conditions for natural gas alone. In a similar sense, linking domestic natural gas prices to crude oil prices is also fundamentally wrong. Current export controls, however, could preclude this competitive price formation.

In today's gas market, alternative fuel prices are higher than existing gas prices based on 65 percent of crude oil. There is also a significant surplus of supply. Therefore, gas price movement under three pricing methodologies can be summarized as follows:

Methodology

Result

65% Oil Parity	- current system
Commodity Value	- prices would rise
Competitive Pricing (no change to export controls)	- prices would fall.

In our Tier II deregulation scenario with market price negotiation only and active producer scrutiny, although opportunity would exist to drive prices down, gas distributors may go the easy route and tend to set gas prices based on competing fuels. If so, residential/commercial prices would rise and industrial prices would fall. No producers would have the opportunity to sell directly.

In a more competitive Tier III environment (assuming existing protection tests), gas prices would fall but more producers would have access to markets. In theory, this competitive pricing scenario would require easier U.S. market access to be more market responsive, more efficient, and provide more equitable market access.

4.8.2 Rate Design Flexibility

The Ontario government has gone on record saying that it would alter any legislation necessary to allow more flexible rate design for Ontario gas distributors. Concern was expressed that utilities have not seriously sought such flexibility.⁷ To capture or retain industrial load, this flexibility could mean moving more fixed costs onto the captive residential market. While this can be considered a form of price discrimination, clear benefits could result from retaining high load factor users.

This rate design flexibility would ease a portion of the downward pressure on natural gas prices but may sacrifice some load in residential and commercial markets as their gas costs would increase. Given the elastic demand curve in the industrial sector and the inelastic demand curve in the residential and commercial sectors, the result would likely be a net gain for the producing industry.

4.8.3 Direct Sales

Concern has been expressed that existing TCPL-distributor gas supply contracts would prevent a smooth transition to a direct

contracting environment. We do not agree. These contracts are based on a demand/commodity rate structure with TCPL fixed costs in the demand portion of the rate. This monthly demand charge paid by the local distribution utility reflects costs of reserving pipeline space for that distributor's maximum contracted volume.

Any firm direct sales into a distributor's market area would be transported by TCPL at its T-Service rate. This rate would mirror TCPL's CD rate, net of the gas cost at the Alberta border. Since the direct sale buyer (be it the distributor or an industrial consumer) would pay a demand charge on the direct sale, it should not be difficult to negotiate an equivalent reduction in the distributors original contracted volume (and therefore demand change). TCPL would recover its total demand charge in any case. Therefore, we do not view the TCPL-distributor contract as a major hurdle.

Similarly, if it were able to secure demand charge relief from TCPL, the distributors should not object to carrying direct sales gas for an industrial consumer in its market area who buys gas directly. The distributor would allocate normal costs to the transportation rate and no other customers would be affected. If the direct sale kept the industrial customer from switching to an alternative fuel, all parties would benefit. Therefore, we do not envision any major difficulty related to the distributor-customer contract either.

The real problem is initially convincing TCPL to carry the direct sales gas. While the transmission side of the business would be basically indifferent to the arrangement, it's brokerage business would face two major problems. First, under the TOPGAS agreements, TCPL is obligated to aggressively market gas. Voluntarily hauling non-incremental direct sales gas would not live up to this obligation. Second, if direct sales proliferated and eroded TCPL's traditional market, the company could face additional take-or-pay liability. All in all, if forced to carry the non-incremental direct sales volumes, TCPL would emerge basically unscathed with its producers shouldering the brunt of the direct sales competition (as long as the APMC continues to approve resultant increases in the Alberta Cost of Service). If these producers could release gas from TCPL contracts to exploit other market opportunities (such as other direct sales or spot exports), we believe the transition to a direct sales environment would be possible.

Footnotes

¹Incentives and subsidies are not trivial, but are excluded in the discussion due to the complexity added by full-cycle resource economics.

²This assumes a burner-tip industrial gas price of about \$5.70 per GJ for firm service in Ontario.

³National Energy Board, Energy Supply and Demand in Canada, 1983-2005, September 1984, p. 57.

⁴Quote attributed to Miguel Wionczek of El Colegio de Mexico related to a joint CERI, Havard University, El Colegio de Mexico study on North American natural gas trade.

⁵Province of Alberta, The Arbitration Amendment Act, R.S.A. 1973, Chapter 88.

⁶A.J. Nixon, Natural Gas Pricing in Canada: An Economic Analysis, CERI, 1981.

⁷Philip Andrews, Presentation to Industrial Gas Users Association, Ontario Ministry of Energy, November 1984.

Chapter 5

POTENTIAL BENEFITS AND COSTS

There will be winners and losers in any decontrol scenario. Below is a qualitative discussion of how gas market participants could fare under each of our four tiers of decontrol. Two caveats apply. First, the status quo described here presumes that the current regulatory regime will continue throughout the period in question. In fact, regulatory policy has always adjusted (albeit slowly) to market conditions. Second, the discussion of all tiers presumes that the process of regulatory change occurs immediately. We have taken the view that "waiting for gas markets to come into balance" does not address current problems and it delays regulatory change for a "balanced market" that may never occur.

5.1 Tier I - Status Quo

Table 5.1 summarizes the potential benefits and costs of a continuation of the current natural gas regulatory regime.

5.1.1 Producers

In aggregate, producing industry revenue should increase from 1983 levels. To date, Canadian gas demand has risen about 10 percent over 1983 levels.¹ Furthermore, studies have suggested that a very large part of domestic natural gas load is relatively insensitive to short-term price trends.² Therefore, barring any unforeseen market changes, the regulatory status quo could be unattractive to the majority of the gas producing industry that has contracted and flowing gas.

On an individual company basis, however, the hardship will continue for producers with shut-in gas and no marketing opportunities. The current system will continue to discourage arms length direct domestic sales. Export opportunities will improve, but will not provide the near-term benefits needed by many small gas producers. The surplus tests will also be a limiting factor. In the longer term, the current regulatory system inflexibility could cause lost load in competitive submarkets such as region-specific residential off-oil applications, industrial boiler load and financially pressed petrochemical plants.

TABLE 5.1
POTENTIAL BENEFITS AND COSTS
TIER I - STATUS QUO^a

Affected Group	Impacts	
	Benefits	Costs
Producers	- higher short-term total revenue - certainty of prices	- inhibited load growth - direct sales by vertical integration only
Consumers	- real price falling - certainty of prices	- uncompetitive gas in some markets - energy intensive industry costs too high
Transmission Pipelines	- TOPGAS costs covered through ACOS - shielded rate of return	- inhibited load growth - unable to compete for direct sales
Distributors	- stable gas prices - opportunity for non-arms-length direct sales	- price insensitive to competition - no chance to benefit from gas-to-gas competition
Exporters		- inflexible floor on export prices

^aThis represents a continuation of the current natural gas regulatory regime.

5.1.2 Consumers

Under the current regulatory regime, natural gas consumers would likely enjoy declining real gas prices assuming the price ratio of gas to crude oil remains at 65 percent and world oil prices remain stable. At the same time, average electricity prices will likely rise in real terms, but aggressively priced surplus supply will still be available to compete with gas.

Energy intensive industries, however, could lose some competitive position if their U.S. competitors also experience decreasing gas prices. This effect could be worsened if North American economic growth contracts significantly in 1985.

5.1.3 Transmission Pipelines

The benefits for TCPL of continuing the existing system are that the relatively comfortable cost recovery methods currently in place would remain. The rate of return insulation from marketing problems would continue to lower the riskiness of TCPL's operations. The Alberta Cost of Service would remain to be a convenient mechanism for coverage of TOPGAS costs.

On the negative side, continuation of existing regulation will likely result in escalating challenges to TCPL's effectiveness as a gas marketer and transporter. Pressure to carry non-arms-length direct gas sales will increase. It is likely that a portion of these sales will be viewed by TCPL as non-incremental and the pipeline could demonstrate considerable reluctance to carry the gas.

5.1.4 Distributors

Local gas distribution utilities have been able to provide their customers with stable gas prices over the past year. In addition, the current system provides those utilities with exploration and production affiliates an opportunity to structure lucrative non-arms-length direct sales deals that capitalize on TCPL's current inability to offer discount ex-Alberta gas.

There are also costs related to the current system. Foremost is the inability of distributors to compete with aggressive marketing of electricity, oil and even coal. The flexibility is not available (or perhaps not utilized) in rate-making and wholesale pricing.

Second, distributors will continue to have only limited access to direct sales supply. The current system confines the possibility of gas-to-gas competition to vertical integration deals. Without widespread access to direct sales gas, distributors will be largely locked into regulated prices.

5.1.5 Exporters

The current system will continue to place a restrictive floor price on negotiated export sales. Indications are that significant potential exists for short-term best effort sales at prices in the \$2.50-\$3.00 (U.S.) range.³ These are largely below the Toronto City Gate floor price. New brokers and direct sellers would likely move more gas to U.S. markets if somewhat more flexibility existed on domestic prices. To the extent that these lower prices could spur new spot sales, revenue gains for certain exporters could occur.

5.2 Tier II - Market Price Negotiation Only

Table 5.2 summarizes the potential benefit and costs (vis-a-vis Tier I - Status Quo) of a move to market negotiation of natural gas prices. This negotiation would be between TCPL and local distributors. The price would be subject to government approval in a fashion similar to the new export system.

5.2.1 Producers

If the producing industry requires a short-term revenue boost, Tier II is likely not the vehicle. Despite the fact that average natural gas prices are lower than those of competing fuels, TCPL-distributor negotiated gas prices would probably face downward pressure. A limited demand response would result in producer revenue reductions. This would be a result of certain competitive forces in marginal markets and general pressure to decrease consumer energy prices.

To compound this short-term cash flow reduction, the problem of market access disparities among producers would not improve. Existing contracting practices would not change substantially. Furthermore, direct sales opportunities (the single market outlet for some producers) would be reduced because the price-based incentive for direct sales would also be reduced. Therefore, producers having

TABLE 5.2
POTENTIAL BENEFITS AND COSTS
TIER II - MARKET PRICE NEGOTIATION ONLY^a

Affected Group	Impacts	
	Benefits	Costs
Producers	- market share retention and development - long-term revenue potential	- short-term revenue loss - no improvement of market access for shut-in gas
Consumers	- lower energy costs	- potential long-term price increases
Transmission Pipelines	- faster take-or-pay retirement - reduced direct sale potential	- more producer scrutiny
Distributors	- improved flexibility to meet competition - improved consumer perceptions of future gas prices	- security of supply may diminish as development activity declines
Exporters	- more flexible floor on prices^b	

^aThis represents negotiations between TCPL and local distributors with the new terms subject to scrutiny by producers and approval by governments.

^bIt is a benefit for direct sellers who have markets at slightly below the Toronto City Gate price.

trouble marketing their gas would likely have no more success under a Tier 11 system.

Most benefits of a Tier 11 system would accrue to producers in the medium and long term. It is unclear, however, whether these benefits will outweigh the costs incurred in the early years of such a transition. The long-term benefits include:

- bigger load base created from price reductions in the short term;
- potential for increased prices as alternative fuel prices increase.

We have calculated that over the medium term, a demand elasticity of at least 0.5 would be required to enable the producing industry to break-even on a 10-20 percent price reduction. CERI analysis has indicated that a medium-term demand elasticity of 0.25 is more likely. Therefore, unless market conditions change substantially, the producing industry will likely suffer a revenue loss with a 10-20 percent price discount.

5.2.2 Consumers

In aggregate energy cost terms, consumers would likely benefit from a more flexible gas pricing system. However, the question is more complex than one of aggregate cost.

First, flexibility works in both directions. Highly competitive sectors would enjoy gas price reductions. In markets where gas is a bargain relative to other fuels, however, natural gas prices could escalate if some additional fixed distribution costs were allocated to these sectors. Unfortunately, these increases could occur in captive residential markets where local oil and electricity costs are high in many regions.

Second, the long-term potential for gas price escalation could have a serious impact on energy intensive industries. While they would certainly benefit in the short term, viability of their businesses could be threatened by potential gas price increases as surplus supply disappears. Given this future threat, industrial gas users may implicitly lower their discount rate by overstating possible economic consequences of high prices several years hence. The result may be

that these energy intensive consumers compute net economic costs to almost any deregulation scenario. This, of course, would not be true for industries in dire need of energy cost reductions today.

5.2.3 Transmission Pipelines

Natural gas buyers and transporters could benefit substantially in a Tier II environment. Most important, TCPL would be virtually guaranteed of modestly increased load as lower prices in the short-term stimulated demand (although not enough to generate revenue gains from producers). Furthermore, the risk of competition from direct sales gas would be reduced because they would still be restricted to non-arms-length deals and the incentive for these arrangements could be somewhat reduced due to lower gas prices. These higher volumes could facilitate faster take-or-pay retirement and perhaps allow more opportunity for facilities additions.

There would be two major costs for TCPL. First, the company would operate as negotiator on behalf of producers. This would undoubtedly mean much more producer scrutiny of TCPL activities (similar to exports). Second, there may be more likelihood of an incentive rate structure for TCPL, making the pipeline more accountable for its sales forecasts. This would increase the riskiness of its rate of return.

5.2.4 Distributors

The ability to negotiate potentially lower city-gate gas prices with transmission companies would allow distributors more control over their marketing program. Facilities utilization would rise and new connections would increase as long as gas prices remained competitive.

One cost relates to security of supply. Near-term gas price reductions without equivalent volume increases will further depress natural gas exploration and development. This will eventually manifest itself in curtailment of low priority load on peak days. Second, consumers may perceive market negotiated prices to be more volatile than prices under the current regime. This perceived uncertainty may inhibit conversions to gas from other fuels. Third, a distributor wishing to initiate a direct sale with a producing affiliate may have more trouble demonstrating a need for the sale if competitive prices are available with existing supply.

5.2.5 Exporters

The obvious benefit for spot gas marketers relates to an immediate reduction in the floor on export prices. This additional flexibility would increase potential sales to all U.S. regions. One cost, however, is that lower domestic prices will result in higher domestic demand, potentially reducing the volume of gas available for new export in the future (unless protection tests were restructured).

5.3 Tier III - Market and Supply Price Negotiation

Table 5.3 summarizes the potential benefits and costs (vis-a-vis Tier I - Status Quo) of a move to negotiation of natural gas prices at both the market and supply ends. This system would be characterized by opportunities for direct contracting and no single price for gas leaving Alberta.

The discussion in this section relates to an early transition to Tier III. It should be noted that a delay in implementation is plausible. If a delay occurred, the downside pressure on price would be less as the existing surplus of gas declines. These downside price pressures related to immediate implementation might be partially avoided by easier producer access to export markets.

5.3.1 Producers

The distribution of producer benefits would depend largely on the marketing savvy and downstream affiliations of individual producers. Aggressive producers with large volumes of shut-in gas could benefit substantially. Successful marketing efforts could increase their sales revenue at the expense of less innovative competitors.

In total, however, the short-term effects on the producing industry would be negative relative to Tier II unless easier U.S. market access was available. The creation of gas-to-gas competition in the domestic market (without greater export access) could drive well-head prices on marginal supply down to the variable cost of production. This could be clearly unacceptable to the Alberta government. Furthermore, if market power was exerted by TCPL in capturing discount markets, the advantages of more equitable access to gas markets could be eliminated.

TABLE 5.3

POTENTIAL BENEFITS AND COSTS
TIER III - MARKET AND SUPPLY PRICE NEGOTIATION^a

Affected Group	Impacts	
	Benefits	Costs
Producers	- aggregate market share retention - marketing opportunities for individual producers	- negotiated prices could plummet without easier access to U.S. markets
Consumers	- substantial short-term price reductions - excellent flexibility	- potential long-term price increases - reduced security of supply
Transmission Pipelines	- increased overall market development	- possible loss of TOPGAS markets - operating complexities
Distributors	- access to direct purchase markets - improved market development	- reduced security of supply
Exporters	- more flexible floor on export prices to allow spot sales	

^aThis represents negotiation of natural gas contract terms at both the market and supply ends. Direct sales would be common.

The result could be significantly reduced producing industry revenue, due largely to a large surplus of gas with no access to alternative markets. This "built-in" surplus caused by export price regulation and protection tests would fuel gas-to-gas competition that could force some producer prices below replacement cost.

5.3.2 Consumers

Natural gas consumers will clearly enjoy lower prices as a result of gas-to-gas competition. An added benefit, however, will be the increased flexibility available with several brokers selling gas into consuming regions. Large industrial users will be able to tailor price and volume terms to suit their operating needs. Potentially, even residential consumers could have gas supply choices among several suppliers with local utilities merely acting as gas transporters.

Two major costs would exist for consumers. First, security of low cost natural gas supply would be reduced. Without U.S. market access, gas-to-gas competition will almost certainly curtail exploration and development activity if gas prices fell too far. Furthermore, most brokerage sales would require backstop arrangements to insure against shortfalls within the supply spheres of individual gas purchasers. These could be difficult to negotiate. Second, natural gas prices would be considerably more volatile. Due to the likely short-term nature of pricing provisions, reduced supply or stronger than expected demand could cause rapid "boom-bust" price swings similar to other commodities. This behavior could be fuelled largely by market expectations.

As long as domestic protection tests remained in place, consumers would likely benefit from a Tier III system. If these tests were loosened and producers allowed to seek markets for shut-in gas, domestic prices would follow U.S. market levels. These domestic prices would likely be higher than under Tier I or Tier II. Therefore, it is clear that while Tier III (assuming unchanged protection tests) would yield lower gas prices for consumers, the risks of long-term price increases are greater if potential demand ever exceeds supply capability.

5.3.3 Transmission Pipelines

The freedom for producers and consumers to contract directly would partially usurp TCPL's role as major gas supplier to consuming markets. While TCPL's dominant position would afford it substantial marketing advantage, direct sales will still occur and likely erode some of TCPL's market share. If TCPL perceived a higher than acceptable level of risk in its brokerage business, it may back out of the market and just run its transportation operations.

Another potential cost relates to the operation of TCPL's pipeline system. With a greater number of shippers moving smaller amounts of gas, TCPL will be required to balance the interests of multiple shippers. Most difficulties will occur when pipeline capacity is approached.

The major Tier III benefit for transmission pipelines will be that natural gas sales should increase with lower prices. It is not clear, however, whether the benefit of accelerated market growth would be offset by costs related to direct sales competitions.

5.3.4 Distributors

Distributors would likely be the major direct purchasers operating in a Tier III environment. They already have the critical customer contacts and could negotiate competitive gas purchase prices. While direct sales by others will evolve in end-use markets, distributors will only be negatively impacted if they have gas purchase commitments they are unable to fulfill due to this intrusion into their traditional markets. This is because local gas distributors would still recoup all costs incurred moving gas for others. Furthermore, their corporate risk could be reduced by a lower emphasis on their role as buyer and seller. Another benefit is that generally lower gas prices would increase opportunities for facilities additions.

5.3.5 Exporters

Spot gas marketers would clearly benefit in the short term from a reduction in the domestic floor price on export sales. In the longer term, however, higher domestic demand could restrict the amount of gas available for new export if domestic protection tests were still in place.

If gas prices fell under a Tier III scenario and if protection tests were relaxed, exporters could enjoy both increased price flexibility and more gas to sell. This is not an unrealistic scenario given producers perception that decontrol could not work unless a simultaneous loosening of protection tests occurred.

5.4 Tier IV - Free Market

Table 5.4 summarizes the benefits and costs of a move to a free market for natural gas. In this environment, all price, volume and pipeline regulation would be removed.

It should be noted that the discussion of this Tier is relatively brief. While a free market certainly operates for other commodities, it is difficult to envision a scenario where the regulation of natural gas trade would be totally abandoned. Since Tier IV is at the end of the regulatory spectrum, it is included here for completeness.

5.4.1 Producers

Providing pipelines do not exercise monopoly power, producers could benefit more from a free market than from a partial decontrol environment. Unrestricted gas trade would enable producers to exploit the most attractive marketing opportunities (assuming pipelines do not exploit their monopoly position). Producers with existing flowing gas would be worse off as gas-to-gas competition could undermine their relatively secure market. Since this Tier would be phased over several years, it is likely that gas markets will have improved, resulting in more attractive prices in all sectors.

5.4.2 Consumers

Domestic consumers would be worse off in a free market. Security of supply may be severely eroded if the protection tests were dismantled. Natural gas prices, while lower in the early years, would likely rise significantly in order to compete for supply. If the U.S. market was strong, producers may direct gas to more lucrative U.S. demand. Given the possibility of higher domestic gas prices, alternative fuels would capture a larger proportion of domestic energy markets.

TABLE 5.4
POTENTIAL BENEFITS AND COSTS
TIER IV - FREE MARKET^a

Affected Group	Impacts	
	Benefits	Costs
Producers	- unfettered market access	- some producers would lose in gas-to-gas competition
Consumers	- low short-term prices	- radically reduced security of supply - long-term prices equivalent to U.S. levels
Transmission Pipelines	- potential to exercise monopoly power - opportunities for brokerage profits	- risk of supply loss - gas-to-gas competition from U.S. pipelines
Distributors	- opportunities for brokerage profit	- risk of supply loss
Exporters	- increase gas supply - more price flexibility	

^aThis represents a scenario where all price, volume and pipeline regulations were abandoned.

5.4.3 Transmission Pipelines

A different operating behavior would characterize TCPL. The company would move to optimize facilities and earn a profit on the buying and reselling of natural gas. If U.S. markets yielded very high prices that domestic consumers were unable to pay, TCPL could suffer substantially if domestic demand fell and supply was diverted to more attractive U.S. markets. Furthermore, TCPL could conceivably compete with Lower 48 pipelines moving U.S. gas into traditional TCPL markets in Ontario and Quebec. The company could, however, stand to make substantial profits if significant margins existed between gas supply prices and possible market prices.

5.4.4 Distributors

The major problem facing distributors would be the availability and marketability of gas when the U.S. was an attractive market option. A cost squeeze could develop in which the prices required to secure supply would render the gas unmarketable in end-use sectors. On the plus side, to the extent that margins did exist distributors could extract economic rent above their current regulated rate of return.

5.4.5 Exporters

Exporters would be the clear winners. New gas supply available to the export market would offer attractive potential for penetration of incremental U.S. load. Canadian surplus gas could be moved rapidly at low prices to U.S. markets. In the long term, the value of Canadian gas in U.S. markets will likely rise. This would increase exporters abilities to attract gas away from domestic buyers. The only negative aspect relates to the U.S. producing industry response to Canadian competition. This would only be a problem if the U.S. supply overhang continued.

Footnotes

¹Canada, Statistics Canada, Quarterly Report on Energy Supply and Demand in Canada, 1984 - II.

²From analysis using CERI's regional energy demand model.

³This is based on the recent applications before the NEB for spot export of gas at prices below the domestic floor.

Chapter 6

CONCLUSIONS

Chapter 3 of this paper examined the nature and mechanics of natural gas deregulation. Chapter 4 examined some of the critical issues related to deregulation and Chapter 5 outlined potential costs and benefits for affected groups.

This chapter will briefly address some of the policy implications resulting from analysis in the preceding chapters. Based on these possible policy initiatives, a fairly easily implemented and workable gas deregulation scenario is described that satisfies the major objectives of deregulation. Its purpose is to tie together the major findings of this paper and provide a starting point for discussion of deregulation options. It is illustrative of how the four tiers can be used to develop a workable market structure.

6.1 Implications for Gas Policy

In assessing the policy implications of natural gas deregulation it is important to understand that even if there is no formal policy change, the marketplace will continue to force a certain degree of flexibility into the system. The industry has demonstrated a good deal of ingenuity by finding solutions within the current regulatory framework. Policy change could help address these market issues in a more orderly fashion.

6.1.1 Policy Options

Table 6.1 is a policy option matrix of the three major spheres of natural gas regulation (price, volume, and pipeline) and the three major reasons often identified for a move to decontrol (market access, cheaper gas, economic efficiency). Each element in the matrix identifies specific policy changes that could achieve the often stated goals of decontrol. There is strong evidence that four broad policy shifts could help improve domestic gas market characteristics. They are:

- **price flexibility** (both up and down) in domestic and export markets;

TABLE 6.1
POLICY OPTIONS MATRIX^a

Reasons for Deregulation	Spheres of Regulation		
	Price	Volume	Transportation
Cheaper Gas for Consumers	- price reduction	- existing surplus tests - direct sales	- cost control incentives - rate making flexibility
Market Access for Producers	- price reduction (only if volumes will increase)	- relaxed surplus tests - direct sales	- marketing incentives
Economic Efficiency	- market responsive pricing	- free trade	- cost control incentives - multiple shippers

^aThis matrix defines changes required under each sphere of regulation (horizontal axis) to achieve the goals of deregulation (vertical axis). Four major policy initiatives are predominant. They are: (1) price flexibility, not simply price reduction; (2) direct contracting opportunities; (3) review of surplus tests; and (4) transportation incentives.

- **review of existing protection tests** and their effects on the gas industry and consumers;
- **direct sales** to provide market access for producers, price discounts for consumers most in need, and efficiency gains resulting from freer trade; and
- **pipeline incentives** for marketing and cost control.

These points are discussed below.

In the short term, unfettered price flexibility in domestic and export markets would allow natural gas supply and demand to respond properly to market conditions. This would likely result in a proliferation of spot export sales and direct domestic sales. Artificial price floors and ceilings inhibit market responsiveness and would result in a continuous state of gas market disequilibrium. In the near term, downward pressure would exist in domestic and spot export markets.

In the medium to long term, the producing side of the gas business considers it essential that any relaxation of price regulation must be concomitant with relaxed surplus tests. It is undeniable that market imperfections will continue if only partial deregulation occurs. As discussed, we believe that the current surplus tests could be reviewed in light of domestic protection alternatives that exist (including long-term domestic supply contracting, protection based on class of customer, and export volume diversion contingencies).

Direct sales are an essential (but complex) component of a move to unfettered competition in the natural gas industry. TCPL's conflicting role as marketer and transporter restricts an immediate move to full scale contract carriage. For example, large scale erosion of TCPL markets by direct sales could occur. Finally, the lack of any type of commodity market for natural gas will make the transition to direct contracting somewhat bumpy. We do believe, however, that direct sales pressure will continue as long as surplus supply exists and that a workable system could be put in place.

Pipeline incentives would not have a major immediate impact on the gas industry. In the longer term, however, cost control and marketing incentives would help ensure that future gas industry growth is rational and that market opportunities are efficiently exploited.

These factors are already in the process of change. Price flexibility could be added with vertically integrated direct sales to ex-Alberta markets. Such direct sales are already pending or flowing. The NEB has already relaxed protection tests in the 1982 Omnibus hearing. The NEB generic hearings are addressing the pipeline incentives question.

6.1.2 Potential Gain

It must be emphasized that these possible policy changes are examined strictly in the context of the natural gas industry alone. Issues related to other sectors of the economy or other Canadian policy goals are not addressed. Furthermore, the individual benefits that accrue from these policy changes may not be sufficient to enable certain groups to support a move from the status quo.¹

Assuming that a move away from the status quo is contemplated, we believe these four policy changes could result in a healthier gas industry in total. The price flexibility and direct sales opportunities would allow more market responsive contracting practices. The relaxation of existing protection tests could ease the pressure on the producing industry. The pipeline incentives would help align pipeline objectives closer to those of producers and consumers.

6.2 A Workable Scenario²

Our analysis suggests that a phased approach to decontrol could be easily implemented. It could be based on policy characteristics drawn from several of the deregulation tiers discussed earlier and be guided by six fundamental principals. Such a natural gas deregulation scenario must:

- reflect less regulation of the Canadian natural gas industry, not simply a change of regulatory focus;
- be simple in design and operation;
- adapt to changing market circumstances and policy environments;
- be easily implemented with a minimum of legislative or regulatory roadblocks;
- not cause major long-term hardship to any specific group; and

- address the three major reasons often cited for decontrol, namely, (1) market access for producers, (2) price flexibility for consumers, (3) enhanced economic efficiency.

Based on these principles, we believe that a less rigid system is indeed feasible. The illustrative system described below (or something like it), shows how a system could be implemented easily and move gas markets toward deregulation in a flexible, phased manner.

These possible natural gas regulatory changes are provided for discussion purposes and are described below.

6.2.1 Overview

Figure 6.1 schematically illustrates one possible system for partial natural gas decontrol. A Competitive Supply Program (CSP), initially say 10 to 20 percent of total gas demand or the incremental sales above a base year level, could be set up to provide an unfettered contracting environment. Any buyer or any seller could participate in the CSP. The right to remove CSP gas from the province would be issued by the provincial government in relatively small discrete volumetric units. These approvals could be based on priorities reflecting individual contract prices or a bidding system similar to land sales.

Gas under the system would flow at privately negotiated prices. Distributors and large industrial users would likely be the active buyers. Supply could be tendered from uncontracted reserves, gas released under "surplus volumes" provisions of existing contracts, or tendered directly from TCPL's controlled capability with approval of its producers. Transportation arrangements would be provided by TCPL and local distributors.

The CSP sales, if at prices lower than the Alberta Border Price, would presumably reduce the floor price on interruptible gas exports to the United States. This may allow more spot sales to proceed. Also, a review of domestic protection requirements would be justified if significant downward pressure on price materialized.³ Alternatively, CSP transactions could be totally free, with no restriction on export of CSP volumes. In such a case, CSP prices could be higher than regulated levels.

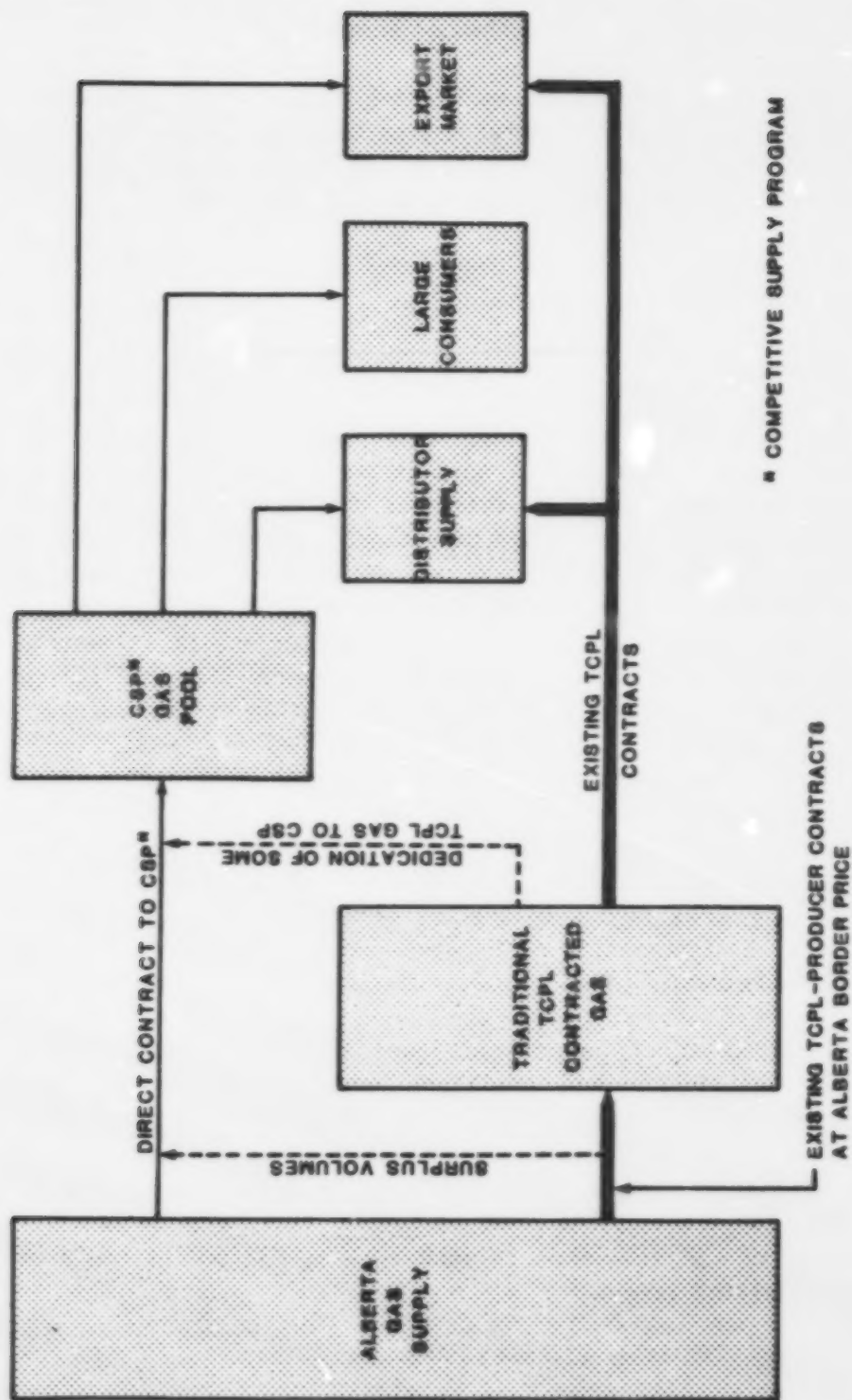


FIGURE 6.1: SCHEMATIC OF POSSIBLE COMPETITIVE SUPPLY PROGRAM

6.2.2 CSP Mechanics

The CSP would require very limited administrative overhead. Three major types of deals would emerge within the CSP. They are:

- direct buyer/seller firm service contracts and a minimum 15-year transportation agreement with TCPL;
- direct buyer/seller spot sales contracts and an interruptible transportation service agreement with TCPL; and
- broker arranged firm medium-term sales (2-5 years) under an umbrella 15-year transportation agreement between the broker and TCPL.

To date, TCPL has not signed firm transportation service agreements for less than 15 years. Assuming the practice will continue, only the above three types of sales could emerge. Short-term firm sales could only be arranged through a broker willing to assume the risk of a 15-year commitment to dedicated pipeline space.

The total allowed CSP removal rights would be set by governments. One of two systems could be used. First, similar to the land system, bids for removal rights could be the basis for allocation. The cash bids received by the government could go back into the Price Adjustment Fund to partially compensate existing producers for markets lost to CSP sales. The second method may be to allocate removal rights based on contract prices for each deal. The highest prices would receive approval. Regardless of the method of allocation, there would be a sunset provision whereby gas would need to flow by a certain date or the removal rights would revert to the government. Such a process would be the only efficient and equitable way to allocate CSP volumes. The system would be relatively simple to operate, require minimal government involvement, yet allow governments firm control of the total volume of deregulated gas in the marketplace.

6.2.3 Flexibility

The CSP would provide an excellent barometer of gas market trends similar to a world spot market for oil. By increasing the amount of allowed CSP gas, governments could implement a phased deregulation policy over time. This process could occur together with

a review of protection tests and pipeline regulation. The CSP could be flexible enough to allow free U.S. market access also.

Another area of flexibility is the freedom for almost any producer to contract gas through the CSP. Existing TCPL producers could dedicate "surplus volumes" or (indirectly) dedicate gas via a sale to TCPL. In any event, TCPL producers' loss of market share would be limited to the size of the CSP, less any truly incremental CSP sales. Furthermore, producers initially choosing not to participate in the CSP could hold their gas for the prospect of higher prices in the future.

In some respects, the flexibility offered by the CSP is similar to market-oriented pricing for export sales. Presumably governments could specify floor and/or ceiling prices on CSP sales to protect the interests of their constituency. While we do not agree with that philosophy, the CSP system would certainly be flexible enough to allow such market intrusions.

6.2.4 Benefits and Costs

Table 6.2 summarizes the major benefits and costs that could be expected with the implementation of a CSP as discussed above.

Uncontracted producers and those selling on a spot basis to U.S. markets would benefit. Domestic market access would improve and the floor on export prices would likely fall in the short term. TCPL producers, in general, could lose domestic sales unless CSP volumes were incremental to existing markets. They still, however, would have the right to use released volumes to participate in the CSP.

Consumers would gain access to market-oriented prices. However, the potential for long-term higher prices always exists. Due to the expected active participation of industrial consumers, the CSP program could be viewed as an attractive replacement for the rigid industrial discount program now in place.

TCPL would likely enjoy increased system load factors. While TCPL market share would fall, no real costs would be incurred except for administrative expenses related to more shippers.

Distributors would also enjoy increased load, but an erosion of market share would occur. Downward renegotiation of minimum bill

TABLE 6.2

POTENTIAL BENEFITS AND COSTS
COMPETITIVE SUPPLY PROGRAM^a

Affected Group	Impacts	
	Benefits	Costs
Producers	- easier market access for some producers - easier U.S. spot sales	- possible market share reduction for TCPL producers
Consumers	- access to market-responsive gas supply	- potential for long-term price increases
Transmission Pipelines	- increased load with market-responsive prices	
Distributors	- increased load with market-responsive prices - relatively easy renegotiation of minimum bill with TCPL	
Exporters	- lower floor on spot sales prices - potential CSP access to U.S. markets	

^aThis relates to a system where a limited volume of natural gas would be traded in a deregulated environment.

provisions with TCPL would likely be possible, given that direct sales shippers would contract for long-term service and pay equivalent demand charges.

Exporters would generally benefit from easier access to near-term spot sales markets and possibly increased export gas supply in the longer term. If free access to export markets was included within the CSP, attractive export prices could draw gas away from domestic CSP sales.

6.2.5 Timing

It has been suggested that any move to partial natural gas market deregulation be delayed until "markets are in balance." The point is that as long as regulation exists, gas markets will never be in balance. In the interim, the problems that plague the gas industry today will continue. Furthermore, new problems, in part caused by regulation, will evolve over time.

The purpose of the CSP or a similar system is to deal with problems that exist today and start the domestic gas market on a gradual path to decontrol. This strategy could provide immediate net benefits today, avoiding potential costs in the future.

6.3 Further Work

To more fully examine issues related to natural gas deregulation in Canada, the advisory committee for this study identified four possible areas of future research. They are:

- alternative methods of volume protection for domestic consumers as well as effectiveness of current protection tests;
- direct sales with related supply and distribution issues;
- cost and benefits of natural gas regulation in general; and
- specific implementation of alternative deregulation proposals.

Common to all of these possible areas for future research is the need for a better understanding of current gas market characteristics. Important factors include existing contracted and uncontracted gas,

flowing versus shut-in supply by company type and better information related to alternative fuel costs, combustion technologies and competitive factors facing Canadian industrial gas users.

Footnotes

¹This is a critical point. While the motives cited for decontrol can be easily identified, clearly not all affected groups will benefit. While the benefits of decontrol may exceed the cost, it is ultimately a political decision to implement policy change.

²This approach to natural gas decontrol is presented for discussion purposes only. It is viewed as one solution to some problems facing the natural gas regulation system.

³It has been argued that the Alberta Border Price is simply a defensive tool to mitigate the effects of the surplus tests on demand for Alberta gas. More flexible export controls could result in a more flexible Alberta Border Price.

APPENDIX A

EVOLUTION OF THE DECONTROL ENVIRONMENT

Appendix A

EVOLUTION OF THE DECONTROL ENVIRONMENT

A.1 Gas Distribution and Pricing

A.1.1 Historical Perspective

The control of the costs of gas distribution have evolved along classic lines of utility regulation whereby the utility is authorized to construct and operate the necessary facilities to distribute the gas in their franchise area. The financing of these facilities is usually accomplished by raising approximately two-thirds of the costs as debt and one-third as equity. The utility is allowed by its regulator to recover its costs of operation and debt service, to depreciate its facilities, and to earn a return on its equity at a level judged to be appropriate. Within this overall revenue requirement, the utility must design and seek approval of specific rate structures to recover its cost from its various customer categories.

Until the mid-1970s the utilities negotiated for gas supply. Alberta distribution utilities developed significant portions of their required supply through directly developing gas fields and supplementing that with further purchases from other gas producers. In other provinces, the transmission pipelines (TCPL and Westcoast) acted as the gas supplier to local utilities.

In all cases, distribution companies acted as exclusive retailers to end-use customers within their franchise area. Starting from the late 1950s through to the mid-1970s, the gas distributors expanded their business very substantially through the combination of a plentiful and relatively cheap gas supply and the opportunity to attain large new market areas.

A.1.2 Changing Environment

From the mid-1970s onward, the first OPEC induced oil price shocks of 1973 and the first federal-provincial pricing agreements in 1975, the operating environment for distribution utilities began to change markedly and continues to the present. These changes are discussed below.

The ability to negotiate buying and selling prices for natural gas was effectively eliminated. East of Alberta this was accomplished by the fixing of Alberta Border and/or Toronto City Gate prices. Inside Alberta, the provincial government subsidized small volume Alberta consumer prices by a provincially funded pricing support system. In British Columbia, the provincial government, through the British Columbia Petroleum Corporation, took over the buying and selling and price setting functions.

Government policy was also set that determined that gas should replace oil as an energy source wherever possible. Expansion of new gas service areas and increases of gas saturation rates in existing service areas was actively encouraged by government policy. This resulted in a series of specific projects and programs including:

- Trans Quebec and Maritimes Pipeline;
- Distribution System Expansion Program and Market Development Incentive Payments;
- Conversion cost support programs; and
- Vancouver Island Pipeline (still pending).

This created significant expansion of distributor service areas and customer counts.

Rapidly rising prices of gas, as fixed by federal-provincial agreements, initiated very vigorous conservation efforts by all segments of the market. Utilities had to struggle to maintain annual loads even though customer counts were rising rapidly. Lower consumptions per customer produced sharp increases in utility tariffs when combined with significant capital expenditures to expand distribution plant to service additional customers.

Higher gas prices and higher utility tariffs began to present serious competitive problems for utilities to maintain competitiveness in industrial markets. East of Alberta, this resulted in loss of industrial markets to competing energy forms (fuel oil, coal, hog fuel, electricity). In Alberta, since gas buying prices at the producer level were not controlled, industrial users (particularly new large ones) have essentially deserted their traditional utility suppliers and contracted directly with producers, using the utilities for transportation service only. The traditional utility suppliers have been unable

to compete because of the limitation in renegotiation of prices under the Alberta Arbitration Amendment Act.

A.2 Transmission

A.2.1 Historical Perspective

The history of pipeline transmission companies in Canada is much shorter than the distribution companies, dating from the early 1950s with the construction of Westcoast Transmission's system in B.C. As is the case with transportation of many commodities in Canada, the transportation of natural gas has had significant government intervention. TransCanada Pipelines was established in 1956 as a result of the famous pipeline debate in the Canadian House of Commons where in order to preserve a Canadian route, the federal government loaned the money required for the Northern Ontario section of the line. In the same time frame, the Alberta government moved to establish Alberta Gas Trunk Line (now NOVA) providing that company with a monopoly franchise to transmit gas from within Alberta to the provincial border for removal. Alberta Natural Gas was formed in the late 1950s to build the connecting pipeline necessary to move Alberta gas to the California market.

The continuing involvement of government in transmission pipelines can be seen in the extension of gas service eastward from Montreal through the TQM system and the proposed Vancouver Island Pipeline. These are a result of government policy to expand gas availability in Canada.

In terms of their tariff making procedures, the transmission companies, with the exception of NOVA (which is regulated on appeal by the Alberta Public Utilities Board) are all regulated by the National Energy Board. The principals of regulation are again the classic utility model and are essentially the same as those applied to distributors.

A.2.2 Changing Environment

The transmission utilities functioned as gas wholesalers until the mid-1970s. They acted as the middlemen in the gas transaction between producers and distributors and negotiated prices of both gas purchases and gas sales. However, since the pricing agreement of 1975, the transmission companies have simply carried out the administrative

function of gas purchase and sale under the specific prices set by governments.

As a direct result of the conservation efforts of the Canadian marketplace, and more recently the non-competitiveness of Canadian gas in the American export market, the transmission companies have witnessed their throughputs stagnate on an annual basis, even though "max day" requirements have continued to increase. This has resulted in a perceived requirement for additional peak day facilities. These factors have combined to produce higher unit throughput costs on transmission systems, further exacerbating the problems of gas pricing.

Another important aspect of the changing environment of the gas transmission companies has been the buildup of enormous take-or-pay liabilities, particularly by TCPL. These take-or-pay problems resulted when high gas prices and the recession slowed demand growth and simultaneously spurred rapid gas supply increases. There was no ability to negotiate gas prices downward due to inflexibilities in the pricing regime.

Further changes to the gas business that have emerged, primarily in the post-1973 period, have been several organizations who perform a gas "brokering" service. They arrange for the purchase of gas supply, obtain gas removal permits from Alberta and export licences from Canada, and negotiate necessary pipeline transportation. These gas brokering organizations (Pan Alberta, Consolidated, Progas, Sulpetro, and KannGaz) simply perform the same function as the gas purchasing/selling arms of the transmission company. They have established a position in the market through their ability to locate markets, contract supply and win necessary removal permits to serve the same general export market areas that were capable of being served by Alberta and Southern (A & S) and TCPL.

A.3 Removal Permits and Export Licences

In Canada, both at the Alberta and federal level, there has always been a policy position taken (through the ERCB and NEB, respectively) that there should be an inventory of gas reserves held for the long-term protection of the domestic market. The level of the protection now is set at 25 times the current year's requirement (25A1). Previously this level had been set at 30 times forecast requirements four years hence (30A4).

While the surplus tests have as a basic principal the intent to protect Alberta or Canadian requirements, there has been a demonstrated tendency of the test procedures to be somewhat restrictive to the expansion of the industry. For example, after the tight gas supply deliverability situation in the mid-1970s, both the ERCB in 1975 and the NEB in 1979 modified their test formulae to incorporate testing procedures for deliverability. As the surplus of supply built up rapidly in the 1980-1982 period, there was substantial pressure on the NEB to be less restrictive and in fact the NEB did relax their procedures significantly, allowing further exports as a result of the 1983 Omnibus Export Decision.

To some extent the evolution of test protection procedures has paralleled the evolution of gas contracting practice. In the early years of the industry, gas was contracted at a rate of 1 Mcf per day for every 10,000 Mcf of reserves, or a 27.3-year life index. Rate of take has evolved through 1/8400 (23 years), to 1/7300 (20-year life), to as low as 1/5500 (15 years) in some cases. Alternatively, deliverability type contracts have been used which do not have a reserve base and may result in an effective rate of take higher than 1/5500.

Since these rates of take are all based on initial reserves, the actual reserves of gas in the ground compared to production rate will be much less than the 25 years of protection required by the protection formulae. This means that the protection formulae can only be met by having substantial reserves held in inventory. Hence, the perpetual supply-side gas surplus.

The required approval of the removal permits and export licences provide governments with a convenient bargaining tool or veto power. This may be applied to the pricing or other provisions that are involved in the actual commercial arrangement involved in the permit or licence. For example, the Alberta government is currently withholding approval of all of the removal permits (except a very small SOQUIP permit) which were recommended by the ERCB in 1982 hearings. They will presumably continue to withhold approval of these permits until it is satisfied with the overall pricing provisions of the various exports under these permits. In the Alberta context, approvals for permits serving domestic consumption have also been withheld in the past over pricing concerns.

A.4 Driving Forces in Evolution of Decontrol

As outlined at the beginning of Chapter 3, the three arguments favouring decontrol of gas trade are: (1) consumers want lower prices, (2) some producers need improved market access, and (3) efficiency gains could occur. Some evidence supports the view that deregulation of the natural gas business already has some momentum.

First, in the present overall mood of the country, there appears to be a trend to reduce government involvement in many facets of industry. In this sense, there is a growing receptiveness to consider ways of disengaging government from more areas of the gas business.

Second, in specific terms, moves have already been made (or are in the process of being made) that are elements of decontrol of the gas industry. For example:

- (a) With a specific floor limit and certain test parameters, export gas prices from Canada to the U.S. have been decontrolled. If decontrol is good for the American market, it obviously forces the question as to whether it would not also be good for the Canadian market.
- (b) Within the officially controlled domestic market, deals are being constructed which have the de facto effect of discounting gas prices outside Alberta. For instance, SOQUIP removes gas from Alberta under a removal permit from its own production (or from companies associated with SOQUIP) for sale to its own markets in Quebec. SOQUIP has recently applied to the ERCB for a tripling of this removal permit again based on its own production. Although this gas production from Alberta leaves the province at the full border price, the participation of SOQUIP in the production revenues results in the net cost of the gas being lower than the official prices.
- (c) J. R. Simplot is utilizing Alberta gas supply purchased from an Alberta producer with whom it participates through utilization of an existing Pan Alberta permit.
- (d) The desire of Ontario fertilizer manufacturers for access to direct sales of Alberta gas was well documented at the hearings conducted by the Ontario Energy Board.
- (e) As was clearly expressed at the recent SOQUIP hearing, considerable frustration is building because existing large purchasers for the Canadian market (Pan Alberta and TCPL) can not participate in discount sales. Similarly IPAC expressed concern that such specific

marketing arrangements preclude most producers from participating and run the risk of establishing the precedent for more such sales which may involve much more significant volumes of gas.

Third, another indicator of decontrol momentum is a modest discount plan for incremental industrial gas sales. This arrangement explicitly recognizes that industrial gas prices were becoming uncompetitive.

Fourth, generic hearings at the NEB are scheduled for both TCPL and Westcoast this fall to examine the methodology of tariff making for both these companies. While the hearings may result in an NEB finding that no changes should be made, the hearings are at least representative of the current thinking that present procedures need to be examined to ensure that they are reasonable, cost effective and responsive to market forces.

In all cases, the principle is that there are willing buyers and willing sellers for discount gas outside of Alberta, and that they are finding limited ways to achieve this within the present framework. Taking all these factors together, it appears evident that there is a definite momentum building for decontrol, or at least a modified and more flexible version of present controls.

APPENDIX B

EXISTING STRUCTURE OF LEGISLATION

Appendix B

EXISTING STRUCTURE OF LEGISLATION

B.1 Canada

B.1.1 Energy Administration Act

This act forms the legislated basis for the setting of domestic natural gas prices at the federal level (Part III - Domestic Gas).

The procedures are laid out which describe the actual implementation of setting prices. Section 50 defines that the federal government, with Cabinet approval, may enter in an agreement with producer provinces to establish prices. It is important to note that the Act does not require the federal government to set prices but does give them the power to do so if they desire.

In Section 52.1 the Act provides the federal government with the power to unilaterally set prices in the absence of a federal-provincial agreement. In Section 53, however, movement of gas outside of a producing province cannot be done except under an appropriate pricing order provided by the National Energy Board. Therefore, under a scenario where no prescribed prices are set by the federal government, any movement of gas outside the province of production would still require a pricing order from the NEB.

Section 64(1) of this Act provides the basis for the export price adjustment fund by requiring that any excess revenues received from resale of gas, beyond the purchasers cost of gas and cost of service, be distributed to producers according to regulations that Cabinet may make.

Part II.2 of the EAA defines the Canadian Ownership Special Charge which is set at 14¢/GJ.

B.1.2 National Energy Board Act

With respect to gas pricing, the NEB under Section 22(2) is required to provide advice to the Minister as requested. The Minister

may request advice which could include the domestic pricing of natural gas.

The powers of the Board regarding tolls and tariffs are defined under Part IV. No company can charge any toll except according to tariffs that have been filed with the Board and are in effect or are a toll or tariff approved by the Board. No discrimination is allowed. That is, a company must charge the same toll for the same class of service to any customer. Section 59(2) of the Act gives the Board specific power to order a company to transport gas for any party wishing such transmission. This power of the Board comes close to creating a mandatory contract carriage for gas pipelines in Canada. Extensive regulations describe in detail the factors to be considered and the procedures to be followed in setting these tolls and tariffs.

Part VI of the Act regarding exports and imports provides the Board with the statutory power to licence exports and imports. Under Section 83 of the Act, the Board is required to satisfy itself that the gas is surplus and that the price is reasonable. In the matter of price, the Energy Administration Act specifies that prices set under its jurisdiction override prices that may be determined by the NEB. It is also under this section of the NEB Act that the Board prescribes detailed regulations regarding applications for export and also specific surplus tests that it will apply when considering export applications.

B.2. Alberta

In Alberta there are several acts which relate to the specific matter of gas pricing. These are described below.

B.2.1 Petroleum Marketing Act

This is the Act which established the Alberta Petroleum Marketing Commission (APMC). The APMC is the administrative agency that carries out the buying, selling and distribution of revenues from sale of natural gas. The APMC also carries out a regulatory function in the determination of the Alberta cost of service applicable to transporting gas in Alberta on the NOVA system.

B.2.2 Natural Gas Price Agreement

This Act provides the basis for the implementation of the federal-provincial pricing agreements including the distribution of additional export revenues.

B.2.3 Natural Gas Price Administration Act

This Act provides the Alberta government with the authority to unilaterally set prices in the absence of a federal-provincial pricing agreement. In the period 1980-1981 when no pricing agreement was in effect, prices were set by Alberta under this Act. They coincided exactly with the prices set by the federal government under the EAA.

B.2.4 Alberta Arbitration Act

Prior to the emergence of the first federal-provincial pricing agreements in 1975, the Alberta government had forced the contract price of gas upwards in a TCPL-Gulf contract arbitration by specifically defining that in an arbitration of gas contract the arbitrator should recognize the premium value of gas as fuel.

Since gas leaving Alberta since 1975 has all been under controlled prices, the Alberta Arbitration Act has not had any effect on pricing of gas leaving Alberta. However, in terms of gas pricing inside Alberta, the Arbitration Act has continued to have effect and was tested in the courts in a gas pricing dispute between Canadian Western Natural Gas (CWNG) and Shell where the courts held that the arbitrator must consider the commodity value of the gas. Since they cannot successfully negotiate downward their existing gas supply costs, CWNG and NUL (the major Alberta utilities) have effectively been shut out of competing in the Alberta discount market.

B.2.5 Alberta Gas Trunk Line Act

While this Act does not have any direct control of gas pricing, it does establish the basis for NOVA's operation. In particular, it gives NOVA the right to establish its own rates without reference to the Public Utilities Board. A party objecting to NOVA's rates may appeal to the PUB for a review.

B.2.6 Public Utilities Board Act

This Act establishes the Public Utilities Board (PUB) in Alberta. The PUB carries out the classic utility regulation role for Alberta gas utilities and, on an appeal basis, considers NOVA rates and cost of service determinations of the APMC. Of notable importance to present gas pricing structures in Alberta was a 1977 decision of the PUB upholding the APMC's determination that take-or-pay interest charges were a proper charge in the Alberta cost of service.

B.2.7 Gas Resources Preservation Act

This Act provides the basis for award of gas removal permits from Alberta by the Energy Resources Conservation Board, subject to Cabinet approval. While it does not control price directly, the rules established by the ERCB for determination of surplus do provide a limitation to the amount of gas that is available to serve the market outside of Alberta. In particular, the ability of the Alberta government to withhold final approval of permits has definitely been a factor in price determinations. At the present time, the Alberta government is withholding approval on five removal permits, all related to gas exports from Canada. It is presumably awaiting the final determination of price on those contracts.

B.2.8 Natural Gas Rebate Act

As a means of providing all Alberta users with access to effective discount pricing, the Alberta government has a support price mechanism in place which places a maximum on the unit price to be paid for the first one Bcf of consumption per customer per year.

B.3 Ontario

B.3.1 Ontario Energy Board Act

This is the key legislation in the Ontario context and describes the powers of the Ontario Energy Board to regulate the Ontario distribution utilities along classic utility regulation principles.

B.3.2 Municipal Franchises Act

This Act describes the procedures for awarding franchises for utility operations. This Act forms the basis for award of franchise rights on a municipality by municipality basis to Ontario distributors. The requirements of this Act would prevent any direct sales by non-franchised distributors, thereby requiring such sales to utilize existing distributors as middleman.

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